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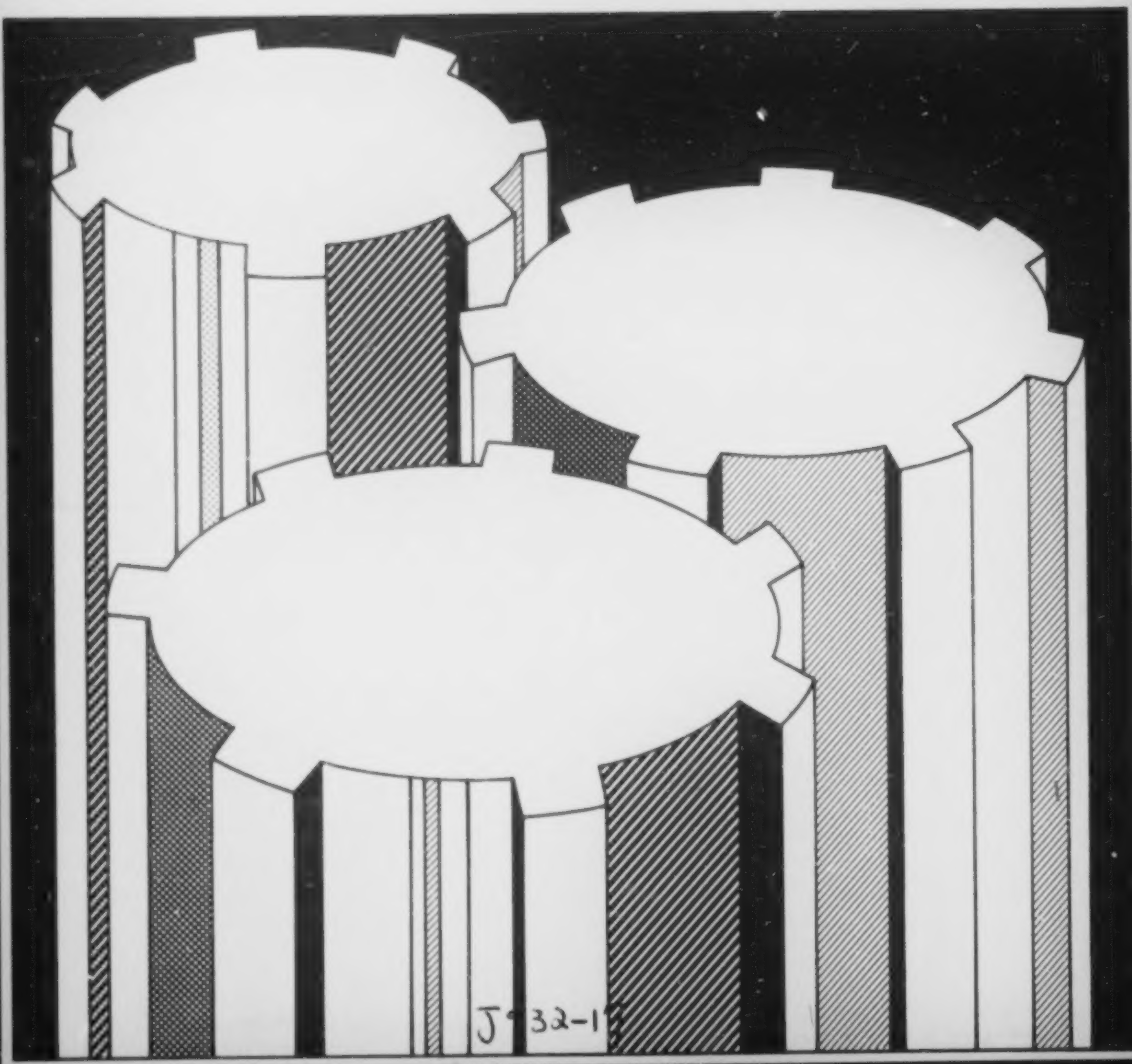
Financial Condition of the U.S. Electric Utility Industry



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CBO STUDY

FINANCIAL CONDITION OF THE U.S. ELECTRIC UTILITY INDUSTRY

The Congress of the United States
Congressional Budget Office

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NOTES

Unless otherwise noted, all dollars are expressed as 1984 dollars.

Because of the normal delays in reporting and obtaining financial data, the financial conditions of utilities described in this report refer to events through June 1985 and, unless otherwise noted, do not take into account the influence of subsequent events.

PREFACE

For many investor-owned utility companies, the past five years have been marked by substantial financial woes. Liquidity problems arose, in part, from overanticipated growth in electricity demand, construction costs of additional power capacity, and a set of economic and regulatory conditions that substantially raised the cost of obtaining capital for some firms. Today, the overall financial condition of the industry is much improved, although a number of firms still remain under financial stress as they attempt to recover the large costs of recently completed or cancelled power plants in the wake of modest demand growth.

Two concerns have arisen because of the financial problems recently experienced by the industry. First, is electricity supply threatened by the temporary liquidity problems of some companies? Second, will the regulatory environment encourage cost-effective investments for meeting future demand or merely promote expensive, expedient solutions for meeting potential supply shortfalls? This study, prepared at the request of the Senate Committee on Energy and Natural Resources, explores these issues and focuses on the problems now confronting the industry and those affecting future electricity supplies. In addition, the study considers what actions the federal government might take to resolve current financial difficulties and potential long-term concerns, as well as examining the role now being played by state regulatory commissions, state governments, utility investors, and electricity consumers. In keeping with the mandate of the Congressional Budget Office (CBO) to provide objective analysis, the report makes no recommendations.

Dan Carol and Thomas Lutton of CBO's Natural Resources and Commerce Division prepared the report under the supervision of David L. Bodde, Everett M. Ehrlich, and John Thomasian. Susan Punnett and Robert Horney provided valuable computational and research assistance. The authors would like to thank members of the Edison Electric Institute and Environmental Action for their generous assistance. The authors also appreciate the comments and suggestions of Richard Bauer, Peter Blair, Paul Joskow, and David Lantz. Patricia H. Johnston edited the report. Patricia Joy typed the many drafts and prepared the report for publication.

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Director

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SUMMARY

Two concerns dominate public policy discussions of the electric utility industry. The first is the disparate financial condition of the nation's electric utilities and whether financially weak firms present a threat to the nation's electricity supply. Most of the industry now has recovered from its acute financal distress of the 1970s and early 1980s, but the circumstances of individual utilities differ markedly. A number of companies still suffer serious financial stress, and a few may be candidates for bankruptcy. While the economic consequences of this financial weakness are speculative, the possibility of electricity supply disruptions is unlikely.

The second concern is the current regulatory system governing electric utilities and how that system may affect electricity supply in the long term. Again, the central issue is not whether supplies are threatened, but rather how to ensure that regulations promote the most cost-effective mix of generation and transmission capacity. Inappropriate regulations will probably not prevent the construction of new power sources, but they could lead to generation and distribution systems that are not well-matched to their task.

CURRENT FINANCIAL CONDITIONS

Most investor-owned utilities are in better financial condition today than at any other time in recent years. Industry-wide liquidity, measured by the ratio of cash flow to dividend payments, stood at 2.7 in 1984, well above the 2.0 ratio usually considered a prudent minimum. The financial recovery of the industry has been reflected in its common stock: by the end of May 1985, the market-to-book ratio (the market value of common stock divided by the depreciated book value of the utility's assets) for the industry as a whole was 108 percent, a marked contrast to the 73 percent of 1980.

The current health of the industry was restored by a reversal of many factors that led utilities into decline in the 1970s. The economic recovery has contributed to a revival in the demand for electricity. Many utilities have finished the extensive and expensive construction programs undertaken during the 1970s. Other utilities have cancelled plants that had become too costly or that would have led to excessive reserve margins; and fuel prices and interest rates have declined.

Despite these overall improved circumstances, the financial condition of several companies remains poor. During 1984, 15 of the 100 largest investor-owned utilities had cash-flow coverage of 1.5 or less. The common equity of eight utilities was valued by the market at less than 75 percent of book value. Excess electricity capacity in some areas may exacerbate these problems for some firms. In general, financially stressed companies are still trying to finish large construction programs, which, when completed, will yield reserve margins well above those needed for assured supply. At the same time, demand growth over the next decade is forecast to be well below past industry averages. Thus, growth in demand will not quickly absorb the excess capacity.

The recent construction programs have also been quite expensive, with capacity additions costing 6 to 8 times more than originally projected. Some of the excess costs can be traced to unanticipated demand changes, some to overambitious construction programs, some to changes in nuclear program licensing, and some to the high cost of obtaining capital during the late 1970s and early 1980s. Most of this cost has not been recovered from ratepayers, and its treatment is the central near-term issue for electric utilities and their regulators.

THE NEAR-TERM ISSUE: ALLOCATING THE COSTS OF RECENT CONSTRUCTION

In nearly all circumstances, state regulatory commissions allocate the risks and rewards of utility investment among ratepayers and stockholders. These regulators judge whether the construction expenditures were prudently incurred by the utility, and whether the completed plant is needed to meet current demand. For either reason, the commissions can decide to exclude from the rate base some or all of the cost of a completed plant. Because of the magnitude of recent construction costs, such regulatory decisions are difficult for commissions to make and for financially stressed utilities to bear.

If regulators allowed full and immediate recovery of all construction costs incurred by the most distressed utilities, the first-year electricity price increases in their service areas could range from 15 percent to 70 percent. Such increases would lower the demand for electricity at a time of excess supply and could depress economic activity in the affected regions. Conversely, state regulators could withhold recovery of a large portion of current construction costs on the basis that they were imprudent, incurred for unneeded facilities, or both. If utilities were denied full or partial cost recovery of new plants, distressed firms might lack the financial flexibility to carry the unrecovered investment, and several have stated such action would force bankruptcy. But even in the improbable event of bankruptcy, it is unlikely that electricity service would be interrupted since supplies in most areas are adequate and bankrupt firms can still be required to operate.

In short, financially troubled utilities and their regulators face a twofold problem. The rapid cost recovery that would relieve a utility's financial stress would also increase electricity prices sharply, thereby depressing the demand for electricity in the service area and, perhaps, leading to further rate increases as fixed costs were spread over a smaller sales base. But postponing recovery of a large portion of burdensome construction costs (or excluding them entirely) could leave a utility in financial peril while sending incorrect signals to the marketplace about the cost of supplying power.

The available evidence suggests that, in most cases, construction costs will be divided between ratepayers and their utilities in such a way as to avoid bankruptcy but to prolong the weakened financial conditions of distressed utilities. The actual supply of electricity may not be threatened by such an outcome, but the nature of future utility investment may be.

PROMOTING LONG-TERM EFFICIENT INVESTMENTS

The long-term concern about the utility industry sometimes focuses on potential shortfalls in electricity supply. It is misleading, however, to infer future shortages simply by comparing capacity now in place with projected future demand under various growth scenarios. To be sure, any growth in demand will eventually require additional generating capacity. But state regulators most probably will never foster a climate in which utilities cannot either build their own generating capacity or purchase electricity from a neighboring system. The real issue is whether current ratemaking practices will encourage the most economic investment decisions to provide cost-effective and efficient electricity supplies in the long run.

Demand Forecasts and Investment Planning

For the nation as a whole, reserve margins are now about 34 percent and should remain at this level for the next few years, as plants now under construction are brought into service. But utilities must plan their investments around demand forecasts that are projected 10 or more years into the future. These forecasts suggest nationwide demand growth ranging from 1 percent to 4 percent, and individual utilities may experience even greater variation. Power purchased from neighboring systems or cogenerators 1/ together with load management, can provide some flexibility by postponing the need to build new generating capacity. But as these options provide diminishing returns, utility managers must choose between two possible courses of action: (1) to meet expected demand growth by beginning power plant construction well in advance of the anticipated need and chance overbuilding; or (2) to defer such additions until demand growth can be more clearly seen and risk shortfalls in baseload capacity.

Either choice could risk economic losses--from excess capacity in the first case, or from inefficient capacity in the second. A decision to build new capacity to meet projected demand requires a major commitment of capital beginning many years before the plant enters service. If the demand forecast was accurate, a large, efficient plant could provide the electricity at a lower cost than any other alternative. But if actual demand was less than anticipated, costs of the underused investment would create economic losses. For example, the carrying charges for a $1 billion investment would be $100 million per year at a 10 percent interest rate.

On the other hand, a decision to postpone construction could risk having to meet higher than expected demand with units not well-suited for baseload service. These units are less capital intensive than baseload plants and can be brought on line more quickly, thus reducing the financial exposure of the utility. But in providing baseload service, their advantages are offset by significantly higher operating and fuel costs.

Estimates suggest that the potential nationwide costs of building excess capacity in the face of low demand are in the $40 billion to $50 billion range, while the costs of meeting unanticipated high electricity demand with inefficient generating units are $30 billion to $40 billion (in discounted 1984 dollars). Falling prices for oil and, hence, all fossil fuels could significantly reduce the penalties of inefficiency. Further, new generating technologies may eventually reduce capital as well as fuel costs by allowing utilities to meet smaller increments of load with smaller, but highly effi-

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1. Cogeneration refers to the sale of excess power generated by a privately or commercially owned company to a regulated utility. For example, a business that produces electricity for plant operations (such as a pulp and paper mill) could act as a cogenerator, and sell its excess power to the utility in its service area. This excess power would then enter the utility's "grid," becoming part of its total electricity supply.

cient, modular plants. The widespread deployment of such technologies before the year 2000 is questionable, however, and the traditional generating options and their variations are likely to remain the principal choice of the utility industry in the 1990s.

Thus, investment decisions in the electric utility industry will continue to require a balancing of risks. The task of regulation is to allow utility managers to make such choices on their economic and technical merits without regulatory bias either for or against new construction. In many cases, current practice falls short of that ideal.

Regulation and Investment Decisions

Ratemaking can influence a utility's decision to invest by making the recovery of construction costs more uncertain than the recovery of fuel and other operating costs. Charges for construction work in progress are often held in a separate account rather than immediately entered into the rate base and reflected in the price of electricity. Only when the plant is placed in service is the accumulated amount, together with a return earned on it, entered into the rate base for recovery of the investment.

This practice can lead to several difficulties. Electricity consumers are first shielded from one price effect of their consumption--the need for new capacity--but later presented with sharp rate increases when the plant begins service. At the same time, the utility's ability to make additional investments is constrained by cash-flow limitations and the recognition by investors that business risk has been increased by the lower quality of earnings.

The most important issue, however, is the implicit treatment of risk. If the demand for electricity proves to be less than forecast when the plant was begun, the utility may be required to bear the carrying costs of the excess capacity until it becomes "used and useful." By contrast, commissions tend to allow the costs of less efficient generation to be more easily and quickly recovered through operating and fuel-adjustment clauses that provide swift rate relief. To the extent that this happens, utility decision-making is biased against incurring capital charges for construction of base-load plants and toward fuel and operating expenditures for construction of smaller but less efficient units. This could lead to a stock of generating equipment less suited to its task than would result if investments had been made under a more balanced regulatory treatment of risk.

THE FEDERAL ROLE

Traditionally, the major responsibilites for providing electricity have been left to utility companies and their state regulators. The available evidence suggests that, in most cases, these institutions are well-equipped to reconcile the current cash-flow needs of the financially stressed utilities with the price increases imposed on ratepayers. Sales of electricity among utility systems have increased markedly, thus helping to balance overcapacity in one area with the demand for economic generation in another. Incipient mergers may strengthen the financial resources of some utility systems. The federal tax code now helps to reduce the financial losses of utilities and their stockholders through provisions that allow such losses to be deducted from income. Further federal aid--through either direct assistance or new tax expenditures--would be inconsistent with the intent of both the Balanced Budget and Emergency Deficit Control Act of 1985 and the tax reform legislation now under consideration in the Congress. Thus, the case for special federal intervention to alleviate the short-term financial distress of some utilities is not compelling. For the long run, however, the Congress might wish to consider ways to improve competition and investment efficiency in the utility industry. Several options are discussed below.

Federal Guidelines

One approach would establish federal guidelines for state regulation. These could be similar in concept to the standards that the Public Utility Regulatory Policies Act of 1978 requires states to consider, but not adopt. The guidelines could suggest that, in order to foster cost-effective investment, the state commissions should provide more balanced treatment of the risks entailed in constructing excess capacity and less efficient generation.

For example, state regulatory commissions could consider better ways to share the responsibility for predicting demand. States could approve (or disapprove, as appropriate) plant costs at several stages in the construction process. This staged review would lower investment risk by guaranteeing eventual cost recovery of the approved portion of the project, even if these costs were not immediately included in the rate base. It would call attention to changes in demand growth, thereby enabling the utility either to abandon construction or to mothball the plant for future use if conditions warranted. The State of Indiana has taken this approach in a law enacted in April 1985. Alternatively, some portion of prudently incurred construction costs could be included in the rate base before the plant entered service.

Other guidelines might allow utilities a higher rate of return on cost-effective investments. When new capacity resulted in net "avoided costs," some portion of the savings could be reflected in utility earnings, thus giving these companies a direct financial stake in providing the least costly generation. This approach might better balance risk and reward in states seeking ways to give their utilities greater responsibility for the economic outcome of investment decisions. Finally, fuel-adjustment clauses could be amended to encourage fuel-switching investments when appropriate.

On the other hand, the federal government has had little influence on state ratemaking in the past, and it is uncertain how much real force voluntary guidelines could have. Further, even voluntary guidelines could be seen as a federal intrusion into the traditional prerogatives of state regulation, and thus encounter resistance regardless of their economic merit.

Fuel Use Restrictions

The Fuel Use Act, as amended, generally prohibits the construction of new generating stations fueled by oil or natural gas. The deregulation of oil and gas markets, together with the recent dramatic decline in the price of these fuels, suggests that these prohibitions be reconsidered. The removal of the gas restriction would yield environmental benefits, stimulate interfuel competition, and encourage utility investments based on the economics of electricity production. Removing the oil restriction as well would further increase interfuel competition, but would also render utilities and their customers more vulnerable to any future disruptions in oil supplies.

Additional Options

Several other options could also be considered. Removing the restrictions of the Public Utility Company Holding Company Act could strengthen the industry financially by facilitating mergers and allowing utility companies to diversify into other businesses. This would risk, however, diverting capital from the electric industry to other businesses and reducing the effectiveness of state regulation.

Second, the Public Utilities Regulatory Policies Act could be revised to permit utilities to own a majority interest in qualifying cogeneration facilities. This could both reduce the planning uncertainties faced by the industry and lower rates paid by consumers, as the utilities and their customers shared the economic benefits that now flow to the cogenerators. This could, however, reduce the benefits derived from nonutility businesses competing to supply electricity. Finally, the incentives for economic sales of wholesale electricity could be improved. The Federal Energy Regulatory Commission is now reviewing its regulation of electric utilities that sell in wholesale markets. Congressional inquiry might await the results of this review.

CONCLUSION

In summary, the electric utility industry is in better financial condition today than at any time since the early 1970s. Its near-term problem--the severe financial stress of a few utilities--is not likely to disrupt the supply of electricity, and there seems to be little reason for federal intervention.

According to growing evidence, the utility industry is responding to an increasingly risky business environment by adopting strategies that emphasize flexibility and limit capital exposure. This response is unlikely to lead to widespread physical shortages of electricity. But, because rate regulation makes the recovery of capital costs more uncertain than the recovery of fuel and operating costs, regulations could bias utility investments toward less cost-effective equipment. The long-term issue, therefore, is to provide regulatory incentives for utilities to use the mix of fuel and capital equipment that will produce the most efficient generation of electricity.

CHAPTER I

INTRODUCTION

The financial difficulties experienced by some of the nation's investor-owned electric utilities have attracted widespread attention over the past two years.[1] This attention is motivated by two key concerns: the allocation of financial losses among the parties at risk and the integrity of long-term electricity supplies.

The first concern pertains to the allocation of costs incurred by a group of utilities that undertook large programs to construct power plants in the late 1960s and 1970s. Some plants are being completed significantly above planned cost; others could not be completed at all; and in yet other cases, the electricity from the completed plants is not needed to meet current demand and hence produces no income. In all cases, state regulatory commissions have been required to allocate the costs of these plants among the various parties at risk: ratepayers in the utilities' service areas; the companies' stockholders; the companies' creditors; and, to a lesser extent, the taxpayers. In most instances, regulators have sought to shield ratepayers from full price effects of the new investments, severely constraining the cash flow of the affected utilities. Because of this financial distress, some observers have questioned whether these utilities can meet their current financial obligations and whether the industry at large will be able to undertake new investments in the future.

Potential constraints on new investment is central to the second concern--long-term electricity supply. Most analysts agree that widespread shortages of electricity are unlikely. But many observe that uncertainty about the regulatory treatment of capital investment, added to the more customary uncertainties of electricity demand and plant cost, encourages utilities to minimize their financial exposure--that is, the amount of funds committed to new plant and equipment in hopes of earning future returns. While some financial restraint is a rational response to currently uncertain market conditions, many utilities now seek to defer investment as a matter of policy.

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[1] Publicly owned or publicly financed electric enterprises have also had financial problems, but these events--such as the $2.5 billion bond default by the Washington Public Power Supply System in 1983 or the May 1985 bankruptcy filing by the Wabash Valley Electric Cooperative--are not directly addressed in this paper. Unless otherwise differentiated, the term electric utility as used in this paper refers only to investor-owned, or private, utilities.

For the immediate future, this policy is unlikely to affect electricity supplies because new capacity is not generally needed. When additions in capacity are eventually needed, however, this perceived market risk--if it is sustained by continued regulatory uncertainty--may lead utilities toward investments that require less capital and shorter construction time, but that produce costlier electricity. Thus, the long-term issue is whether the present regulatory climate provides incentives that lead to the most economic mix of fuels, generating equipment, and transmission capabilities.

CAUSES OF THE CURRENT FINANCIAL DIFFICULTIES

Although causes vary by company, the roots of the current financial problems of the troubled utilities can be traced to ambitious construction programs initiated in the late 1960s and 1970s under assumptions of high growth in electricity demand and high oil prices. These expectations proved incorrect. Overall demand rose only 2.5 percent annually from 1970 to 1983 in contrast with the 7 percent annual growth experienced from 1930 to 1970, thus removing the imperative for new power plants to provide expanded service. At the same time, declining oil prices and rising construction costs--the latter resulting from increases in inflation, interest rates, labor costs, and construction lead times--substantially weakened the incentives to substitute new plants for old. Utilities that cancelled new plants or completed their building programs before 1982 have generally fared well financially. But firms still engaged in expensive new plant construction have experienced significant cash-flow shortages. Several firms have had to omit or substantially reduce common stock dividends to sustain operations.

Regulation also played an important part in creating these financial conditions. Health, safety, and environmental requirements sometimes led to costly "backfitting" and construction delays. Equally important, state utility commissions--which set the allowed rates utilities can charge their in-state customers--often did not permit utilities to recover construction costs until a plant was fully "used and useful." Firms often had to borrow substantial funds at high interest rates to sustain construction. Even today, state regulatory decisions barring recovery of investments deemed "imprudent"--as defined by utility rate procedures--continue to cloud some firms' chances of recovering the costs of nearly completed power plants.

THE FEDERAL ROLE IN THE SEARCH FOR SOLUTIONS

The federal government has only a small role in allocating the large costs arising from the utility construction campaigns of the 1970s. Ratemaking has traditionally been a state prerogative, in which the costs and benefits of electric utility investments are apportioned between the utility's investors and its customers. Federal actions might be appropriate, however, in addressing longer-term concerns about risk, uncertainty, and investment inefficiency in the utility industry. In part, this is because the federal role in utility ratemaking has increased as more electricity is traded across state boundaries. The portion of electricity sales subject to regulation by the Federal Energy Regulatory Commission (FERC) has increased from about 5 percent in the 1970s to about 29 percent in 1984. Federal authority is likely to grow further to the extent that utilities meet new demand with power purchased from neighboring utilities rather than their own investments in new power plants.

In addition, the federal government is directly involved in the choice of fuel and generating technology. The Powerplant and Industrial Fuel Use Act of 1978, as amended, prohibits the construction of new, large power plants that burn natural gas. The Public Utility Regulatory Policy Act of 1978, as amended, provides incentives for industrial cogeneration to supplement or even displace power plants owned by electric utility companies. 2/ Finally, the Public Utility Holding Company Act of 1935, as amended, has been instrumental in shaping the structure of the industry. Thus, the federal government is already heavily involved in shaping long-run incentives for investment efficiency.

For both the short-term problem of cost allocation and the long-term one of investment efficiency, this study examines the following questions:

- What are the common causes for utilities' financial stress and do sufficient similarities exist across utilities to allow a generic solution to the problem?

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2. Cogeneration refers to the sale of excess power generated by a privately or commercially owned company to a regulated utility. For example, a business that produces electricity for plant operations (such as a pulp and paper mill) could act as a cogenerator, and sell its excess power to the utility in its service area. This excess power would then enter the utility's "grid," becoming part of its total electricity supply.

- What options are available to utilities, state regulatory commissions, and the state and federal governments to relieve financial stress, prevent bankruptcy, or lessen the effect of potential utility failures?

- What options are available to help ensure that efficient, low-cost electricity capacity is built when needed?

CHAPTER II

THE CHANGING FINANCIAL CONDITIONS OF THE PRIVATE ELECTRIC UTILITY INDUSTRY

This chapter discusses the changing financial conditions of the investor-owned utility industry over the past two decades. Twenty years ago, the costs of building new power plants tended to be predictable and, most important, declining. The goal of regulators--to provide low-cost electricity to consumers--and the goal of utilities--to earn a fair return on investment for their stockholders--were in relative harmony. Through a series of events in the 1970s, however, the costs of new construction rose dramatically and the growth in demand for electricity dropped unexpectedly. In many cases, state regulators were reluctant to pass on to ratepayers the costs of expensive--and sometimes excess--capacity. Absorbing these costs caused a decline in the financial position of the private utility industry. Although most firms have recovered substantially from the industry's poor financial performance of 1980, some utilities currently engaged in new plant construction continue to experience significant liquidity shortages. Several firms, in fact, have been forced to omit common stock dividends to sustain operations.

CURRENT COMPOSITION OF THE INDUSTRY

The electric utility industry possesses about 600,000 megawatts (Mg) of generating capacity. Coal was the primary source of electricity generation in 1984, providing 43.6 percent of total U.S. capacity. Oil and natural gas accounted for almost one-third (32.2 percent) of total capacity. Nuclear generation in 1984 amounted to 10.7 percent of total capacity, with 84 reactors licensed to operate. Hydro power constituted about the same percent (10.4 percent) of total capacity as nuclear generation. Other sources, including pumped storage and geothermal, accounted for 3 percent of capacity in 1984. Because of their lower relative operating costs, however, coal and nuclear plants supplied disproportionately more electricity--55.9 percent and 15.9 percent, respectively--than would be suggested by their relative shares of generating capacity. 1/

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1. North American Electric Reliability Council, *Electric Power Supply and Demand 1984-1993: 1984 Annual Data Summary Report.*

Not all regions have the same access to sources of power, and great variations exist in generating capacity by fuel type across the country. Coal is the dominant source of power (exceeding 50 percent) in the Mid-Atlantic, the Mid-West and the Southeast.[2] Nuclear power accounts for between 6 percent and 21 percent of the electricity generated in these regions. Oil exceeds 20 percent of the generating capacity only in the Mid-Atlantic and the Northeast. In the Southwest, gas is dominant while hydro power is important mostly in the West.

Physical and Financial Integration

Partly because of the high capital investment costs, the investor-owned electric utility industry is significantly integrated both financially and physically. The financial integration among utilities is apparent from the number of joint partnerships undertaking new plant construction and the number of publicly owned utilities participating in these partnerships. About half of all new nuclear-power plants under construction, for example, involve joint ownership by at least two utilities, with public utilities (such as electric cooperatives) often included among the partners. These joint efforts allow utilities to pool their resources, without entering into a formal merger agreement.

The electric power "grid" is evidence of physical integration. Grids provide common transmission links among plants and over large regions spanning several states. Such interconnection allows firms to sell their excess capacity to firms needing power.[3] The frequency of these interstate transactions have increased over the last decade, and now represent about 29 percent of electricity sales. Three major grids serve the continental U.S. market. For example, the eastern two-thirds of the United States, is served by one grid.

THE ERA OF STRONG UTILITY GROWTH

From 1950 to 1970, electric utilities experienced a strong and stable period, marked by steadily increasing returns on equity, relatively high stock prices, and robust growth in electricity demand. With economies of scale and technological advances encouraging larger and larger plants, and with integration within and across firms improving efficiency, generating capacity more than quadrupled while real prices decreased by about 30 percent. Reserve margins--the difference between total generating capacity and anticipated peak demand--were comfortably maintained at an average of 22 percent.[4] These margins helped ensure a reliable supply of electricity even if demand increased faster than expected.

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[2] Ibid., p. 79.

[3] See Department of Energy, *The National Power Grid Study* (1980). In fact, excess power is not necessarily "shipped" to far away places. If a plant in one locale can spare power to another locale far down the transmission link, each intermediate locale between the sending and receiving areas simply passes on the power as it is received from the plant up the line. Thus, the excess power is eventually supplied to the needy area.

With declining real costs and prices, the goals of both the state regulators and the electric utilities were accommodated quite easily. Rate hearings needed to be held much less frequently than today, and the subject of such hearings often was not how much to raise prices, but how much to lower them.

Regulatory requirements affecting utilities were also considerably less complex during this period. Laws concerning the environment and power plant siting had little impact before 1970. Partly as a result of this benign regulatory environment, the average construction period for new baseload plants in the 1960s was about six years, compared with eight to twelve years today.[5] Plants started now usually must receive a certificate of need from the state public utility commission before construction can commence, in addition to satisfying other applicable health and safety regulations.

UNCERTAIN ENVIRONMENT OF THE 1970s

At the beginning of the 1970s, the bright outlook of the preceding two decades continued to dominate the investor-owned utility industry. Anticipating relatively low inflation, moderate interest rates, stable or declining fossil fuel prices, the installation of new and cheaper nuclear plants, and a continuation of modest environmental and safety regulations, utilities expected to double capacity every 10 years. The relationships between most utilities and their regulators--the public utility commissions--also appeared harmonious and optimism prevailed among investors.

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4. See Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry* (1980).

5. The term "baseload" refers to the number of hours a plant is relied on to produce power over the course of a year. A baseload plant typically supplies power for that portion of electricity demand that remains stable throughout the day, compared with a "peaking unit" which may be used to meet power demand surges. A baseload plant typically operates over 65 percent of the time. If stoppage for scheduled maintenance is included, a baseload plant can be considered to operate most of the time.

The 1970s marked the start of dramatic changes, however. First, fossil fuel and nonfuel operating and maintenance costs rose dramatically as a result of the 1973-1974 Arab oil embargo and inflation. Utilities passed on these additional costs to industrial and residential customers by charging higher electricity rates. Second, the anticipated growth in electricity demand failed to materialize. As a result, many of the capacity additions planned before 1970 for completion by 1975 were not economically justified. Third, increased regulatory requirements caused construction delays and created new uncertainties for capacity planning. Finally, construction costs for new baseload plants increased beyond utilities' original expectations (especially for nuclear plants) as a result of several factors, including construction delays, high interest rates, changing safety regulations, and construction problems brought about both by utility firms and contractors. Public utility commissions often refused to allow firms to pass on these costs to customers. These adverse conditions led to an unexpected decline in utility earnings and strained the relationship between the utilities and their regulators. By 1980 the industry's average market-to-book ratio--a financial measure used to indicate stock market performance--had fallen to its lowest level in two decades. Investors viewed those utilities with unfinished nuclear power plants with the greatest caution.

Rising Variable Costs

In 1970 the average variable cost of supplying electricity rose for the first time in more then a decade.[6] Higher oil and gas prices resulting from the 1973-1974 oil embargo and the 1979-1980 oil shortage caused even greater increases in utilities' operating costs. In 1973, for example, electric utility plants paid an average of 87.6 cents, 169.8 cents, and 73.1 cents (in 1984 dollars) per million Btu for coal, heavy oil, and natural gas, respectively. By 1981 the real prices of these fuels had risen twofold for coal, fourfold for oil, and fivefold for gas--to 181.6 cents, 627.6 cents, and 403.8 cents (in 1984 dollars) per million BTU, respectively.[7]

Similarly, nonfuel operations and maintenance (O&M) costs also rose faster than inflation, in part from increased environmental regulation. Between 1970 and 1980, O&M costs for fossil-fuel plants increased from 2.07 mills to 2.55 mills per kilowatt-hour (in 1984 dollars).[8] These costs for nuclear plants rose even more, increasing twice as fast as nonfuel costs for fossil-fuel plants for the whole decade, and doubling between 1977 and 1980 alone. [9]

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[6] Variable costs include fuel and the majority of nonfuel operations and maintenance costs.

[7] Department of Energy, Energy Information Administration, *Monthly Energy Review* (September 1985).

[8] Department of Energy, Energy Information Administration, *Thermal-Electric Plant Construction Cost and Annual Production Expenses in 1980* (1981).

Because utilities could not obtain regulatory approval for price increases quickly enough to keep pace with rising fuel and other O&M costs, their cash-flow positions became strained. For example, as a result of the unexpected rise in fuel costs following the Arab oil embargo, Consolidated Edison Company was forced to skip a cash dividend on common stock in 1974. These cost increases also placed state utility commissions under pressure to grant electricity price increases. Automatic fuel adjustment clauses were established in many states to eliminate the necessity for frequent rate reviews. While this process assured the utilities sufficient cash flow for new fuel purchases, customers quickly felt the effects of the nearly twofold increase in oil and gas prices in 1979 and 1980. (Not all states employed this technique, however. Some states, such as Missouri and Michigan, prohibited their use and 15 other states eventually introduced legislation to restrict such pricing.)

Changes in Growth of Electricity Demand in the 1970s

Over the 40-year the period from 1930 to 1970, the demand for electricity grew at an average annual rate of 7 percent, doubling every 10 years. During the 1960s, falling electricity prices and rising disposable income spurred demand growth. In 1970 these major determinants of demand were expected to continue the 7 percent trend in demand growth. But between 1972 and 1984, electricity prices increased threefold, and real disposable income grew only 2.7 percent per year, compared with 4 percent annually during the 1960s. These unexpected events dampened the increase in electricity demand from the high rates experienced in the 1960s to only 2.5 percent annually over the 1970-1983 period. [10]

At 2.5 percent annual demand growth, capacity requirements would double only every 30 years, rather than every 10 as previously expected. Overforecasting actual demand led to overinvestment in new plants, many of which had to be cancelled. This phenomenon of overforecasting demand was shared by electric utilities throughout the industry and not limited to the small group of utilities that subsequently became financially distressed. But most utilities that cancelled unneeded plants between 1978 and 1983 emerged in relatively good financial shape.

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[9] Ibid., p. 289.

[10] Peak demand, which also shapes supply requirements, rose 3.9 percent over the 1970-1983 period, also below previous expectations.

Increased Regulatory Requirements

Utilities became subject to a host of new regulatory requirements during the 1970s. Plants burning fossil fuels were regulated by the Clean Air Act of 1970 and its amendments in 1977. In 1971 nuclear plants were found to be subject to the requirements of the National Environmental Policy Act for environmental impact statements.[11] Most states and many localities instituted laws governing power plant sites during the decade. These new requirements tended to increase licensing and construction periods for both nuclear and coal power plants.[12]

The 1979 accident at Three Mile Island (TMI), a nuclear generating station owned by General Public Utilities (GPU), also led to increased regulatory requirements.[13] Following the incident, the Nuclear Regulatory Commission (NRC) suspended issuance of plant operating and construction licenses for one year. The Kemeny Commission, formed to investigate TMI, criticized NRC's approach to safety, and recommended that NRC require certain changes in equipment and design. The ensuing changes in requirements for quality assurance and safety equipment delayed construction schedules as plants nationwide were "backfitted" to meet these new standards. The TMI incident is reported to have caused construction delays of almost one year and capital cost increases of 2 percent for the typical nuclear plant built in its aftermath.[14] In addition, 11 states reacted to the TMI accident by passing public referendums designed to limit the development of nuclear power.

Rising Construction Costs

Increased operating costs, lower than foreseen demand growth, and expanded regulatory requirements were only part of the evolving financial crisis in which some utilities found themselves in the 1970s. The other principal factor precipitating the industry's financial difficulties proved to be rising construction costs, primarily caused by increases in labor and material costs, higher real interest rates, and longer construction lead times.

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[11] See *Calvert Cliffs v. Atomic Energy Commission*, 449 F.2nd 1109 (D.C. Circuit, 1971).

[12] A recent study found regulatory requirements to be an important source of construction delays, along with labor and technical problems and deliberate delays because of reductions in demand growth. See Electric Power Research Institute, *Power Plant Construction Leadtimes* (February 1984).

[13] For a thorough description of the events surrounding the near core meltdown at TMI, see Staff Reports of the President's Commission on the Accident at Three Mile Island (Washington, DC: Kemeny Commission, October 1979).

[14] See Charles Komanoff, *Power Plant Cost Escalation: Nuclear and Coal Capital Costs, Regulation, and Economics* (New York: Komanoff Energy Associates, 1981).

Construction costs generally rose most rapidly (relative to overall inflation) for nuclear plants. The cost (in 1984 dollars) of a typical nuclear plant entering commercial operation increased from about $715 per kilowatt (kw) in the 1971-1974 period, to about $1,389 per kw in the 1981-1984 period. The average cost of a plant expected to enter service in 1985 or 1986 has risen to about $2,600 per kw measured in 1984 dollars.[15] The magnitude of these increases exceeds the level of cost escalation experienced in new coal plant construction (see Table 1).

Much of the growth in the costs of new nuclear power plants can be traced to construction delays and the attendant compounding of carrying charges. The construction period for nuclear utility plants has stretched from six years in the early 1970s to about 10 to 12 years for recently licensed nuclear plants.[16] Causal factors were labor and equipment problems, plant redesign work necessitated by regulatory changes, and deliberate construction delays because of the waning demand. State regulatory commissions have also found significant utility mismanagement in some construction programs.[17] The accrual of interest charges because of these delays can be quite large, especially during an inflationary period. For a nuclear plant begun in 1972, with debt financing at 12 percent and labor and materials inflation at 9 percent, the final cost of the plant would be 30 percent higher if the plant were completed in 1984 (12 years from start of construction) than if it were completed in 1980 (eight years from start of construction). Not all utilities incurred significant construction delays, however. A few nuclear plants entering service in the 1979-1983 period were completed in fewer than eight years.

RESPONSES TO CHANGING FINANCIAL PROSPECTS

Between 1974 and 1984, electric utilities cancelled 97 nuclear generating stations and 75 coal plants that were planned for operation in the late 1970s

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[15] See Department of Energy, Energy Information Administration, *Nuclear Power Plant Construction Activity 1984* (July 1985).

[16] See Electric Power Research Institute, *Power Plant Construction Leadtimes* (1984); and Office of Technology Assessment, *Nuclear Power in An Age of Uncertainty* (1984).

[17] The New York Public Service Commission, for example, has recently disallowed $1.5 billion of the costs of the Long Island Lighting Company's Shoreham facility because of imprudent management practices.

TABLE 1. ANNUAL RATES OF GROWTH IN COAL AND NUCLEAR CONSTRUCTION COSTS, 1973-1983 (In percents) [a]

Time Period	GNP Price Deflator	Handy-Whitman Construction Index	Coal-Fired Capital Costs	Nuclear Capital Costs
1973-1979	6.4	10.7	18.9	16.5
1979-1983	7.2	6.8	5.9	29.6

SOURCE: Congressional Research Service Report No. 84-236(s), December 31, 1984, based on *Statistical Abstract of the U.S.* (1984); and Department of Energy, Energy Information Administration, *Thermal Electric Plant Construction Cost and Annual Production Expenses (1981)* and *1983 Survey of Nuclear Power Plant Construction Costs*.

a. All growth rates are based on current dollars.

and early 1980s.[18] The Department of Energy (DOE) estimates that the sunk costs for the cancelled nuclear plants amounts to $10 billion.[19] Even with the high number of plant cancellations, reserve capacity margins increased 50 percent during the decade (from 21 percent to 33 percent) because of the completion of many other plants and the decline in demand growth. More cancellations might have occurred, but current regulations appear to have spurred some utilities to complete plants since their costs could only be recovered when the plant became "used and useful."[20] Thus, some utilities preferred to risk the cash-flow problems of construction so that the plant costs would at least be entered into the rate base (see box). Construction postponements--through the "mothballing" of unfinished plants--were also disadvantageous because high borrowing costs continued

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[18] Edison Electric Institute, *Electric Power Survey* (January 1985).

[19] Robert Borlick, *Nuclear Plant Cancellations: Causes, Costs, and Consequences*, Department of Energy, Energy Information Administration (April 1983).

[20] "Used and useful," a term used in ratemaking procedures, indicates that a plant is needed and operational. A plant typically must be used and useful before a utility may charge its customers for the investment, unless the regulatory agency specifically allows the utility to charge for construction work in progress.

Utility Ratemaking and the Rate Base

Because utilities are regulated monopolies, the electricity price that they can charge consumers is established by state public utility commissions for intrastate sales and by the Federal Energy Regulatory Commission (FERC) for interstate sales. While FERC ratemaking rules are uniformly applied throughout the country, state ratemaking practices can vary by state, although they tend to conform to certain established guidelines (which are also consistent with FERC practices).

Generally, a state commission holds a quasijudicial hearing to determine a utility's prices. Utility revenues are considered adequate when the prices charged for electricity sales are equal to the cost of providing electricity ("cost of service"), plus some subjective "fair" rate of return on the value of the utility's assets (the rate base). Allowable **service costs** include fuel expenses, operation and maintenenace costs, depreciation of capital stock, administrative expenses, and taxes. An estimate of total expenses for the coming year is typically derived by using an historical "test year," often the most recent 12-month period for which complete financial data is available.

The **rate base** reflects an electric utility's gross capital investment less accumulated depreciation--in essence, the value of the property that is "used and useful" in producing and delivering power. As such, it includes the value of land, buildings, generating stations, and transmission facilities owned by the utility. These assets can be valued by one of three methods: original cost, replacement cost, or--reflecting a compromise between the first two--"fair value." Most states employ fair value accounting. Once the rate base is determined, an allowed rate of return is applied. This rate generally reflects the weighted average rate of return the utility must pay for long-term debt (bonds) and preferred or common stock (equity). Many state commissions require that a plant must be operational to be placed in the rate base. Others may allow a portion or all of the construction work in progress (CWIP) to be included.

during this period and because tax write-offs of losses could only be taken for cancelled plants.

Utilities that quickly cancelled planned projects in the mid-1970s in response to dampening demand generally fared better than those that did not cancel plants until the late 1970s and early 1980s. Firms in the latter category continued to face mounting liquidity problems, since variable costs, as well as dividend and interest payments, increased faster than revenues. Many of these firms are still experiencing liquidity constraints today.

Regulator Response

Many state utility commissions reacted sharply to the building of expensive plants in a time of lower-than-expected demand. In order to shield consumers from large price increases, many commissions did not permit utilities to recover either the carrying or capital costs of plant construction (called construction work in progress, or CWIP) until the plant was fully used and useful. Instead, construction and interest charges were entered in a special account termed Allowance for Funds Used During Construction, or AFUDC. Under AFUDC accounting, the utility did not actually realize a cash return on its investment during construction. Instead, the book value of the account accumulated until the plant was placed into service, at which time the AFUDC account was entered into the rate base and began to earn a return on the utility's investment.

This accounting device had two effects. First, utilities' current cash income declined, as the construction-oriented AFUDC account rose from 12.9 percent of reported income in 1969 to almost 50 percent by 1983.[21] And second, the size of the AFUDC account often reached several billion dollars by the time the plant was completed. The sudden entry of this amount into the rate base could cause sharp price increases, some ranging from 15 to 70 percent. To counter such price shocks, state regulators began employing "phase-in" plans to lessen the increases of including the entire cost of a new plant into rates all at once. Such measures further delayed utilities' recoveries of their investment costs.

Finally, regulatory commissions began to scrutinize utility plant cancellations more thoroughly. A study of 71 plant cancellations through June 1983 revealed that, in 24 percent of the cases, regulators ruled against any cost recovery.[22] In 62 percent of the cases, cost recovery was granted for prudently incurred costs and, in the remaining cases, some return on the prudently incurred investment was allowed. Eight state utility commissions, however, ruled against any cost recovery, even if the initial plans for construction appeared prudent. Sunk costs for a number of these plants amounted to millions of dollars.

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[21] Edison Electric Institute, *Financial Review-1983: An Annual Report on Investor-Owned Electric Utilities* (July 1983).

[22] Ibid, p. x.

Investor Response

Utility investors soon realized that regulatory decisions about the recovery of plant costs could greatly influence a utility's final earnings. If investors viewed a state's regulatory decisions as unfavorable, utilities in that state had to pay higher interest rates to attract capital. Table 2 presents one view of how investors rank state commissions. The rankings range from A, excellent, to E, very poor. In general, state regulators that allowed some or all construction costs to be recovered before a plant was used and useful and allowed a return on equity above 15 percent were most well-regarded by investors.

Irrespective of regulatory climate, utility investors especially penalized nuclear utilities. As nuclear-power costs increased faster than expected in the 1970s, especially after the Three Mile Island accident, investors began to exact a risk premium from utilities seeking to finance nuclear construction. 23/ These effects can be seen clearly in Figure 1.

In 1970, of the utilities rated by Standard and Poor's Corporation, 96 percent of those with nuclear plant construction programs received bond ratings of A or better, thus suggesting a relatively good long-run prognosis for their financial health. (Bonds rated BBB or higher are considered investment grade; those ranked BB and below, speculative). Yet, by 1980, only 67 percent of the utilities with nuclear programs had investment grade ratings. The ratings on some utilities' bonds fell so low by the 1980s that many institutional investors were prohibited by law from buying them, because of their inferior quality. By contrast, investors' views of non-nuclear utilities changed very little during this period. Although the mean bond rating for nuclear utilities had degenerated to BBB by 1983, the mean bond ratings for nonnuclear utilities remained within the AA to A range.

CURRENT CONDITION OF THE INDUSTRY

The investor-owned electric utility industry reached its lowest point financially in 1980. The utilities average market-to-book ratio--a financial measure often used to characterize a firm's anticipated financial performance in the stock market--declined from 2.53 in 1965 to 0.73 in 1980, the lowest level in more than two decades. 24/ Long-term debt for utilities

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23. U.S. Department of Energy, *Investor Perceptions of Nuclear Power* (May, 1984).

24. As a ratio of the market price of a utility's stock and the book or resource value per share of stockholder investment, the market-to-book ratio indicates the value investors in financial markets attach to the management and organization of a utility. As the market-to-book ratio declines below 1, the sale of new stock will usually dilute the value of the existing stock.

TABLE 2. EXAMPLE OF INVESTOR RANKING OF STATE REGULATORY COMMISSIONS AND PRACTICES IN 1984

State	Type of Rate Setting	Allowed ROE (In Percents) [a]	SBI Rank [b]
Alabama	Year-end original cost; no CWIP	15.0	C-
Arizona	Year-end fair value; some CWIP	16.2	C-
Arkansas	Year-end original cost; some CWIP	14.2	C-
California	Average original cost; no CWIP	16.0	B
Colorado	Year-end original cost; some CWIP	14.4	C
Connecticut	Year-end adjusted cost; some CWIP	16.4	B
Delaware	Average original cost; no CWIP	14.9	C+
District of Columbia	Average original cost; some CWIP for pollution control only	[c]	D
Florida	Average original cost; some CWIP	15.6	B
Georgia	Year-end original cost; some CWIP	15.5	C-
Hawaii	Year-end original cost; some CWIP	15.0	C-
Idaho	Average or year-end original cost; CWIP in emergencies only	14.9	C-
Illinois	Year-end original cost modified for fair value; some CWIP	15.6	B
Indiana	Year-end fair value; no CWIP	15.8	C+
Iowa	Average original cost; no CWIP	14.7	C-
Kansas	Year-end original cost; CWIP during final year of construction	15.5	C
Kentucky	Year-end original cost; CWIP	15.0	C
Louisiana	Average original cost; some CWIP	[c]	E
Maine	Average original cost; no CWIP	16.0	D+
Maryland	Average original cost; some CWIP	14.8	C
Massachusetts	Year-end original cost; no CWIP	16.0	C
Michigan	Average original cost; no CWIP	14.5	D
Minnesota	Average original cost; some CWIP	14.7	C+
Mississippi	Average original cost; no CWIP	15.5	D
Missouri	Year-end original cost; no CWIP	15.6	C-
Montana	Average original cost; no CWIP	14.2	E
Nevada	Year-end original cost; some CWIP	15.0	C
New Hampshire	Average original cost; no CWIP	16.1	C-

(Continued)

TABLE 2. (Continued)

State	Type of Rate Setting	Allowed ROE (In percents) [a]	SBI Rank [b]
New Jersey	Year-end original cost; some CWIP	15.8	C+
New Mexico	Year-end original cost; some CWIP	15.5	C+
New York	Year-end or average original cost; some CWIP	15.0	C+
North Carolina	Year-end original cost; some CWIP	15.3	C+
North Dakota	Year-end or average original cost;	14.5	C-
Ohio	Average original cost; CWIP when plant is 75 percent complete	16.9	D+
Oklahoma	Year-end original cost; some CWIP	15.0	C+
Oregon	Average original cost; no CWIP	15.8	B
Pennsylvania	Year-end original cost; CWIP only for pollution control	15.5	C-
Rhode Island	Average original cost; no CWIP	14.4	C-
South Carolina	Year-end original cost; some CWIP	14.3	D
South Dakota	Average original cost; no CWIP	14.0	D
Texas	Year-end original cost; some CWIP	16.3	B
Utah	Average original cost; some CWIP	15.0	B
Vermont	Average original cost; some CWIP	16.0	C+
Virginia	Year-end original cost; some CWIP	15.0	C-
Washington	Average original cost; no CWIP	15.8	C
West Virginia	Average original cost; some CWIP	14.5	D
Wisconsin	Average original cost; some CWIP	14.8	B
Wyoming	Year-end original cost; no CWIP	14.8	C-
FERC [d]	Year-end original cost; some CWIP	15.5	B

SOURCE: Congressional Budget Office, based on Salomon Brothers, Inc., *Electric Utility Regulation - Semiannual Review* (New York, N.Y.: Salomon Brothers, August 8, 1985).

NOTE: CWIP = Construction work in progress.

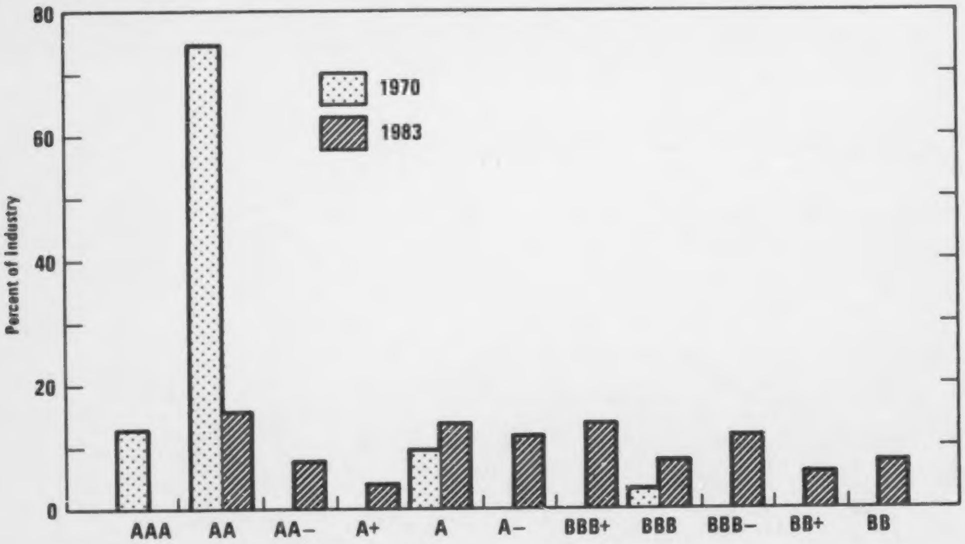
a. ROE is the return on common equity allowed by state commissions in recent decisions on representative major electric utility rates.

b. Ranking is provided by Salomon Brothers, Inc. Regulatory Rank (SBI Rank), with A ranking highest and E lowest.

c. Not available.

d. The Federal Energy Regulatory Commission (FERC) sets rates for electricity that is sold wholesale across state borders.

Figure 1.
Bond Ratings for Nuclear Electric Utilities, 1970 and 1983



SOURCE: Standard and Poor's Bond Rating.

grew from $42.2 billion in 1970 to $124.8 billion in 1982, with interest charges amounting to $11.5 billion alone in 1982.[25] Utilities' current cash income also declined, as the construction-oriented AFUDC account grew to represent about 50 percent of utility earnings by 1983.

The industry's financial condition has improved markedly in the last five years, however, in part from the economic recovery which has spurred revenues from electricity sales. Industry-wide liquidity, measured by the ratio of cash flow to dividend payments, stood at 2.7 in 1984, well above the 2.0 ratio usually considered a prudent minimum. In addition, the industry's average market-to-book ratio rose to 1.1 in June 1985, up from its 20-year low of 0.73 in 1980. In the course of this overall recovery, the industry has become stratified into two distinct sets of firms, each with particular financial problems. The first group--made up of the financially healthy majority of investor-owned utilities--is experiencing robust growth in earnings. Indeed, about 30 companies will generate 100 percent of their cash needs internally by 1987. For the most part, these firms are not now

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25. Mark Luftig and Neal Kurzner, "Electric Utility Regulation--Semi-Annual Review" (New York, NY: Salomon Brothers, Inc., February 26, 1985).

building any baseload plants, but they are concerned that future construction efforts will be plagued by the regulatory and investment problems of the last decade. These firms, therefore, seek measures to reduce investment uncertainties in the long-term. The second group of firms have more immediate problems: they were still engaged in major construction projects in 1983 and 1984 and were experiencing liquidity shortfalls.

Utilities with Liquidity Constraints: 1983-1984

About 15 of the 100 largest investor-owned electric utilities experienced cash-flow shortages in 1983 and 1984 (see Table 3). These firms were identified using a four-fold screening process described in Appendix B. Five of the firms identified (Consumers Power, Long Island Lighting, Public Service of Indiana, Public Service of New Hampshire, and United Illuminating) had market-to-book ratios below 50 percent. Middle South Utilities--a holding company--and Central Maine Power had market-to-book ratios of between 50 and 80 percent. The remaining eight firms (Dayton Power and Light, Toledo Edison, Ohio Edison, Union Electric, Philadelphia Electric, Kansas Gas and Electric, Gulf States Utilities, and Kansas City Power and Light) have shown considerable improvement since they were first identified by the CBO screening procedure and were selling common stock at 80 percent or more of book value by mid-1985.

These 15 utilities have experienced liquidity constraints only in the last several years. In 1974, for example, this group of firms exhibited no liquidity problems, having a cash-flow coverage to dividends ratio of 2.5, relative to the industry average of 2.6. (A cash-flow coverage ratio is defined as income available to common equity plus noncash expenses less noncash credits divided by dividends paid.) A high cash-flow coverage ratio (above 2) indicates the firm has adequate liquidity; as the ratio falls below 2, however, liquidity problems arise. Cash-flow coverage ratios for this group of firms eroded to 1.5 during 1984, compared with an industry average of 2.7.

Although specific causes vary by firm, construction programs have probably been the most important overall reason for the liquidity problems of these firms. Like most investor-owned utilities, these firms were considered excellent long-term bond risks in 1974, rated A or higher. With long construction delays and the erosion of regulatory and/or investor support, bond ratings dropped and capital costs increased. Public Service of New Hampshire, for example, with a rating of BBB, was forced to raise approximately $450 million in bonds with effective interest rates ranging from 19 to 21 percent in order to continue building its still unfinished Seabrook

TABLE 3. ELECTRIC UTILITIES WITH LIQUIDITY CONSTRAINTS IN 1983 AND 1984 [a]

Firm	Plant	Location of Service Area
Central Maine	Seabrook 1 Millstone 3	Maine
Consumers Power	[b]	Michigan
Dayton Power & Light	[c]	Ohio
Gulf States Utilities	River Bend 1	Louisiana, Texas
Kansas City Power & Light	Wolf Creek	Kansas, Missouri
Kansas Gas & Electric	Wolf Creek	Kansas
Long Island Lighting	Shoreham	New York
Middle South Utilities	Grand Gulf 1 Waterford 3	Louisiana, Arkansas, Mississippi
Ohio Edison	Perry 1 Beaver Valley 2	Ohio
Philadelphia Electric	Limerick 1	Pennsylvania
Public Service of Indiana	[b]	Indiana
Public Service of New Hampshire	Seabrook 1 Millstone 3	New Hampshire, Maine, Vermont
Toledo Edison	Perry 1 Beaver Valley 2	Ohio
Union Electric	Callaway 1	Illinois, Iowa, Missouri
United Illuminating	Seabrook 1 Millstone 3	Connecticut

SOURCE: Congressional Budget Office.

a. These utilities were identified by comparing a series of standard financial ratios over the 1983-1984 period as described in Appendix B. These historical ratios do not necessarily imply similar circumstances today.

b. Plant deferred or abandoned.

c. Plant being converted to a coal-fired facility.

plant. By comparison, bond offerings by A-rated firms were sold for 12.9 percent during 1984.[26]

As construction programs are completed, remaining liquidity problems should begin to ease. If they do not, the troubled utilities may face more difficult choices. (Other options to resolve the cash-flow difficulties for this group of firms are discussed in Chapter III. The long-term issues confronting the industry are presented in Chapter IV.)

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26. Mark Luftig and Neal Kurzner, "Electric Utility Regulation--Semi-Annual Review," Salomon Brothers, February 26, 1985.

CHAPTER III

RESOLVING THE CURRENT FINANCIAL STRESS

In general, those electric utilities with liquidity constraints incurred significant financial losses from investments in plants that may remain unfinished or whose production costs would exceed those of alternative supplies, such as power purchased from other utilities. To continue operating, many of these companies have undertaken a variety of cost-cutting measures, such as omitting dividend payments or reducing maintenance activities. They have also sought rate increases to help pay for plants still under construction, abandoned, or recently completed. Most of these rate cases are still pending. This chapter describes the efforts of financially troubled utilities to increase their liquidity and presents both nonfederal and federal options that could assist them.

State regulators are primarily responsible for distributing economic losses from power plant investments among ratepayers, utility stockholders, and creditors. Although the apportionment of these losses can generate considerable debate, both utility managements and their state regulators have the resources and the incentives to seek solutions to avert possible bankruptcies. If a default occurs, the federal bankruptcy process should ensure both continued electric service for utility customers and a reasonable resolution of the excess cost issue. It is not clear, however, whether a bankruptcy declaration would increase or decrease the ultimate costs of electric service for the utility and its ratepayers. The federal government possesses only limited options (including the bankruptcy process itself) to aid distressed utilities. In the absence of widespread threats to electric service or to the public health and safety, federal intervention appears inappropriate in addressing short-term problems of liquidity. However, the federal government might play a more appropriate role in addressing longer-term concerns about risk, uncertainty, and investment efficiency.

NONFEDERAL APPROACHES TO EASE FINANCIAL CONSTRAINTS

Faced with rising construction costs and inadequate revenues to cover their costs, including maturing debt, financially distressed utilities have several traditional, nonfederal alternatives to increase their liquidity. Many of these nonfederal options are already being employed, including:

- Austerity programs that cut labor and maintenance costs;
- Stock dividend reductions or omissions; and
- Rate relief plans that allow either construction work in progress (CWIP) to be included in electricity prices or cost recovery for cancelled or completed plants.

Other nonfederal options would be somewhat more drastic, supplying potentially more economic relief to a utility, but typically involving more difficult and far-reaching decisions by the firm's management, state legislators, and regulators. Such alternatives include:

- Mergers or sales of plants or firms;
- Refinancing of debt through private means; and
- State assistance efforts such as loans or direct subsidies.

These six measures--alone or in combination--appear to offer ample means to meet the immediate cash-flow requirements of distressed utilities.

Not all the options could be used by all the troubled utilities. Availability would depend largely on individual financial conditions and the stage of new plant construction. As a result, the relative effectiveness of each option in easing liquidity constraints would vary across firms. The costs of implementing these options--distributed among ratepayers, utility investors, utility creditors, and taxpayers (through unrecovered investment "write-offs")--would also vary. Some alternatives, such as reduced service, would primarily affect utility ratepayers, while the effects of other options, like dividend omissions, would be felt mostly by utility stockholders.

Austerity Programs and Service Reductions

About 20 percent to 25 percent of the cash-flow requirements of distressed utilities could be met, at least temporarily, by reducing operation and maintenance activities. In general, the traditional approach used is to reduce service levels by undertaking permanent or temporary reductions in the work force and by deferring maintenance of facilities.[1] Consumers Power, for example, cut operation and maintenance by 10 percent in 1984 and permanently eliminated 571 full-time positions. Public Service of Indiana (PSI), on the other hand, chose to reduce its full-time work force temporarily by 25 percent, saving the company about $49 million during a recent 12-month period. PSI has recently requested a permanent rate increase, however, to allow for the rehiring of some of these workers and for maintenance activities that can no longer be deferred. Similarly, the Long Island Lighting Company (LILCO) is seeking to reinstate 231 of the 700 positions it eliminated in 1984. This suggests that austerity measures may not be sustainable beyond one year because many maintenance requirements cannot be permanently eliminated or even postponed for long.

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[1] Utilities do have other austerity options which are not considered here. First, utilities might defer payments to fuel suppliers and other creditors for very short periods. Second, utilities might delay or cancel construction, thereby reducing their short-term cash requirements. Savings from deliberate construction delays could be eroded, however, by rapidly rising interest or construction costs. Cancellation savings would depend on regulatory approval of plant construction costs and could be eliminated altogether in the short term because the utility might be forced to repay all tax credits earned during construction immediately upon plant cancellation.

Austerity measures might also affect utility customers by lowering the quality of service. PSI, for example, argues that a failure to restore enough revenues to pay for deferred maintenance activities could lead to power line problems and, eventually, serious service breakdowns. Ultimately, it could affect investors and creditors. Austerity programs and service reductions, therefore, appear to offer only limited benefits to utilities, depending largely on existing service, maintenance, and labor contract requirements.

Dividend Omissions

Alternatively, utilities could increase retained earnings by deferring or suspending payments of cash dividends to common or preferred stockholders. Several utilities, in fact, have already employed such measures (see Table 4). For example, Long Island Lighting Company (LILCO) has not paid a quarterly dividend on its common stock since March 1984. This has saved the company roughly $45 million on an annual basis. More recently, Middle South Utilities has omitted its third quarter 1985 dividend to preserve $85 million in cash for company operations, while it awaits several pending requests for rate relief. The use of this option--assuming common stock dividend omissions only--by the remaining distressed utilities appears capable of meeting about half of these companies' short-term liquidity requirements.

The ability of companies to employ such measures usually depends on company charter rules and SEC regulations. Generally speaking, a company can suspend common stock dividends permanently but can only defer preferred dividends for four quarters before preferred stockholders are allowed (by company charter) to replace existing management with a new board of directors. Clearly, utility investors bear the short-term cost of these types of measures not only through loss of dividends but also because dividend deferrals lead to a decline in stock value. Less obvious, however, is the longer-term consequence of dividend suspensions--the increased cost of capital, especially that raised through future stock sales. This cost will be borne by future ratepayers.

Rate Relief

Most, if not all, immediate cash requirements of distressed utilities could be met if state regulators allowed rates to rise enough to cover the costs of recent construction. Because of the high excess costs of these investments, however, state regulators are unlikely to force utility ratepayers to bear the full costs through large rate increases. State regulators will generally grant

TABLE 4. RECENT DIVIDEND DEFERRALS BY MAJOR UTILITIES

Company	Common Stock Dividend	Preferred Stock Dividend
Central Maine	Omitted since 4/85	Paid on schedule
Consumers Power	Omitted since 10/84	Paid on schedule
General Public Utilities	Omitted since 11/26/79	Paid on schedule
Long Island Lighting Company	Omitted since 3/84	Suspended declaration of preferred dividends payable after 9/30/84
Middle South Utilities	Omitted 3rd quarter 1985 dividend	Paid on schedule
Public Service of New Hampshire	Omitted since 4/19/84	Omitted since 4/19/84
Public Service of Indiana	Dividend cut 65% since 2/84	Paid on schedule
United Illuminating	Dividend cut 38% since 7/84	Paid on schedule

SOURCE: Congressional Budget Office.

rate increases for only that portion of the utility's investment that was prudently incurred--whether the plant is completed or not--and disallow investments or portions of investments that they consider imprudent. 2/

Distressed utilities, for their part, are seeking to recover plant construction costs as quickly as their regulatory agency will permit. The speed and nature of such cost recovery is an important element of utilities' revenue positions, and, as such, the outcomes of these pending rate cases are crucial to their financial well-being. The most useful type of cost recovery depends largely on the stage of plant construction. For a utility with a cancelled plant, rate increases to cover all or some portion of its lost investment are desired. Utilities with ongoing construction seek to include their construction costs in the rate base as soon as possible, through CWIP treatment. Finally, utilities with completed plants seek to have the full costs of the plant (not just the carrying charges) recovered through rate increases from the moment the plant is used and useful.

Cost Recovery for Deferred or Abandoned Plants. Plant cancellation by itself can help ease a utility's financial burden, but may not be enough to relieve financial stress fully unless some cost recovery for the abandoned facility is allowed. For example, both Consumers Power and Public Service of Indiana deferred or abandoned the construction of expensive nuclear power plants in 1984. Although future construction costs have been eliminated, the final distribution of these projects' sunk costs (about $3.4 billion for Consumers Power's Midland project and $2.5 billion for PSI's Marble Hill facility) will ultimately be decided by the relevant state regulatory commission. The state commission may decide that the utility acted prudently in building and later abandoning the project, and allow full recovery of the project's costs, including an earned rate of return on the investment. On the other hand, the regulator may determine that the entire project was imprudent and allow only limited cost recovery. Such a decision could lead to severe cash-flow shortages or perhaps bankruptcy in some cases. 3/ The most likely outcome in both examples is that the Michigan and Indiana com-

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2. Rate base disallowances preclude a utility from earning a return on that portion of the investment that is disallowed. Excess plant expenditures are most often disallowed because of management imprudence that caused construction cost overruns or because the plant is deemed excess capacity. A utility that cancels construction in response to changing demand forecasts may, therefore, be considered more prudent by its regulators (and will fare better in a rate case) than a utility that successfully completes what turns out to be an unneeded plant.

3. See, for example, Consumers Power Company's Supplement to Amendment to Application (Revised Step 3 Rate Relief Request), Case No. U-7830, Filing of October 11, 1984.

missions will disallow some portion of each project's cost as imprudent, and allocate the sunk investment between utility stockholders, ratepayers, and federal taxpayers (through tax write-offs of the unrecovered investment).[4] In any event, proposals for additional federal or state aid may be premature until these cases are decided in 1986.[5]

Cost Recovery for Construction Work in Progess. Utilities involved in large-scale construction projects argue that all or some part of prudent expenditures for construction work in progress should be included in rates and earn a return, even before the plant is fully used and useful. Without CWIP treatment, utilities may incur higher borrowing costs to sustain cash flow and construction efforts. (See Appendix B for further discussion of the effects of CWIP treatment on utility cash flow.)

Regardless of the claims of either CWIP advocates or opponents, little question exists that the inclusion of CWIP in the rate base helps a utility continue construction, especially when CWIP represents a large portion of the utility's assets. The injection of new rate revenues through CWIP reduces the need to seek additional outside financing at high interest rates. A prime example is El Paso Electric Company, a partner in the three-unit, $9.3 billion Palo Verde nuclear project. El Paso's construction practices differed relatively little from other utilities that eventually incurred liquidity problems. Indeed, El Paso had the highest percentage of its assets tied to nuclear construction of any utility in the nation, yet its performance in other key financial ratios was superior to other utilities that were less exposed (reflecting higher investor confidence). A principal reason for its good financial position is that the Texas regulatory commission granted significant amounts of CWIP in El Paso's rate base in August 1984.[6] This suggests that without CWIP El Paso might have found itself in the same position as the distressed utilities, which typically did not have CWIP in their rate base.

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4. Among previous nuclear plant cancellations involving sunk costs of greater than $50 million, state commissions have mostly permitted either full or partial cost recovery. See Robert Borlick, "Nuclear Plant Cancellations: Causes, Costs, and Consequences," U.S. Department of Energy, Energy Information Administration, DOE/EIA-0392 (April 1983), and Edison Electric Institute, "Regulatory Treatment of Cancelled Plants: Survey Update of Cases in 1983," Special Report, SR 84-01 (March 1984).

5. So far, both the Michigan and Indiana utility commissions have addressed only the companies' emergency rate relief requests, which are designed to assure that normal day-to-day electric service is maintained. The companies' permanent rate requests--to recover sunk plant costs--will be decided after the emergency rate cases are settled.

6. It is also important to note that El Paso had a higher than average demand growth rate.

Including some degree of CWIP expenditures in the rate base could provide significant revenues to several of the distressed utilities. Full CWIP inclusion generally would provide as large a new liquidity source as employee cutbacks or service reductions. Companies with completed or abandoned plants (Kansas City Power and Light, Kansas Gas and Electric, Middle South, Long Island Lighting, Union Electric, Public Service of Indiana, and Consumers Power) are now seeking alternative forms of rate relief through rate base treatment of completed plants or cost recovery of abandoned plants. Compared with the dividend omission measures, which could erode investor confidence in the company, CWIP inclusions could send positive signals to the investment community regarding the company's cash position and its future regulatory treatment. This could serve to reduce additional financing costs in the period required to complete the plant, which, in turn, could lower future plant costs to both ratepayers and utility investors. Combined with common dividend omissions and short-term austerity measures, CWIP treatment for eligible distressed utilities could have satisfied most of these utilities' incremental (above 1984 levels) cash-flow needs for 1985.

Cost Recovery for Completed Plants. For distressed utilities with recently completed plants, full and immediate recovery of plant costs through rate increases would improve the utilities' financial positions in the short term. However, the high costs of these plants, some of which exceed the size of the utilities' rate base, would lead to price increases ranging from 10 percent to 67 percent. Such "rate shocks" could depress economic activity in the affected service area and reduce the demand for electricity in the long run. Thus, state regulators will usually employ a phase-in plan to lessen the price effects of bringing completed power plants into the rate base all at once. 7/

Generally speaking, phase-in plans gradually introduce the costs of the plant into the rate base, with the unincluded portion of the plant accumulating both interest and the allowed return on equity until it enters the rate base. This approach delays the full return on the stockholders' investment, but, because interest accumulates on the unincluded portion of the plant, there is no net loss to stockholders. 8/ For current ratepayers, phase-in plans offer some relief from the potential inequity of subsidizing rates paid by future customers. Moreover, phase-in plans offer two other potential

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[7] These phase-in plans are also being linked in some cases with gradual CWIP treatment of plant costs (before completion of the plant) to help smooth the rate shock effects.

[8] Stockholders could lose a portion of their investment if--as part of a phase-in plan--a state PUC disallows certain construction expenditures as imprudent or some percentage of plant capacity as excess.

advantages (relative to full and immediate plant cost recovery) to utilities themselves: first, they can reduce public opposition to higher rates; and second, they may lessen the possibility that higher rates will lower demand enough so that total revenues to the company in fact decline after the rate increase.

On the other hand, phase-in plans may force the utility to issue additional stock or borrow additional capital to offset the lost income from that portion of the plant excluded from the rate base. This has the effect of reducing utility cash flow in a period when many companies already rely too heavily on external capital sources. In addition, utilities and investors are concerned about the risks of future regulatory actions that could further delay full recovery of plant investment. In the worst case, their investment might never be recovered. This added risk disturbs investors and could be reflected in stock market prices.

Rate base phase-in plans have been instituted for Union Electric and the Kansas utilities, and are likely to be employed for those distressed utilities that will soon complete plant construction. The relative success of these phase-in plans in stabilizing the utilities' financial positions depends on how they affect utilities' cash flow. Most distressed utilities need substantial cash now. Large amounts of plant expenditures not included in the rate base immediately could weaken already distressed companies.[9] Given adequate rate relief by the relevant state commissions (and realized added revenues despite the rate shock), however, this alternative appears capable by itself of providing enough financial stability for eligible utilities.

MORE RIGOROUS APPROACHES TO AID CASH FLOW

The previous section explored readily available schemes to aid cash flow, some of which are already used. Use of these approaches--austerity programs, stock dividend omissions, and allowing plant cost recovery through rate increases--could have provided nearly all the additional cash necessary in 1985 (above 1984 levels) to meet utilities' short-term liquidity requirements. For any remaining cash needs, more severe measures, such as merging with another firm, debt refinancing, or state assistance, might be necessary.

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[9] As an example, the Kansas Corporation Commission, in granting phased-in rate relief to Kansas Gas and Electric and Kansas City Power and Light, allowed the companies to earn a return on less than one-third of their investment. Because of this decision, these companies can be expected to experience cash-flow shortages and may need to suspend payment of stock dividends. See "Utilities to be Denied Profit on Two-Thirds of Wolf Creek Investment," *Associated Press*, September 12, 1985.

Mergers and Sales

One solution for a utility whose construction program is threatened by poor financial health could be the sale of the plant to another utility or merger with another company that is able to continue construction. For a utility that will need additional power in the future, purchase of all or some of the plant's future output might be an attractive alternative to beginning a new facility from scratch. This alternative is probably limited, however, because adequate transmission lines may not exist, and significant regulatory hurdles may face any such proposal (see Chapter IV discussion of option to liberalize the Public Utility Holding Company Act to allow for mergers and diversifications). The greatest impediment to sale or merger, however, is the unattractively high cost of the plants under construction. The high cost of the Seabrook plant, for instance, made it difficult for the Maine utility co-owners to sell off their share of the plant when compelled to do so by the Maine Public Service Commission (PSC). 10/

Despite similar difficulties, however, Cleveland Electric Illuminating Company has recently announced plans to merge with Toledo Edison (one of the troubled utilities identified earlier), subject to stockholder and regulatory approval. The two companies are already co-owners of the Perry 1 and 2 and Beaver Valley 2 nuclear units now under construction. Moody's Investors Service Inc. believes that the proposed merger could improve the combined company's credit quality in the long run. Moody's lowered its rating on Toledo Edison's preferred stock in May 1985. 11/

Although the possibility of similar mergers with financially troubled utilities appears rare, each of the distressed utilities, because of their large capital investment programs, has substantial quantities of unused tax benefits, such as investment tax credit carryovers. These tax benefits potentially could be used by profitable utilities or other nonutility companies by merging with the utility. A similar option using selective safe harbor leasing (through which the utilities could effectively "sell" these tax benefits) would have the same potential benefit for utilities without the need to seek a merger partner. This option is discussed later in this chapter. All these options are essentially neutral from the standpoint of investors (who could

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10. In late 1984, the Maine PSC ordered Central Maine Power, Bangor Hydro Electric Company, and Maine Public Service to sell their combined 10 percent share in Seabrook 1. Most recently, Eastern Utilities Associates, a Boston-based holding company, has offered the Maine companies about 14 cents to 15 cents on the dollar for their Seabrook investment. See "A New Gamble on Seabrook," *New York Times*, August 6, 1985.

11. See *Wall Street Journal*, June 26-27, 1985.

actually benefit from a merger) and ratepayers. Options that would use tax benefits not otherwise employed would, of course, increase taxpayer costs.

Private Refinancing

Utilities unable to meet immediate liquidity needs through internally generated cash usually seek external sources of capital. Troubled utilities facing cash-flow shortages often rely on banks to provide this type of short-term (one year) relief. Most of the utilities identified in Chapter II have exhausted this option, however, and commercial banks are reluctant to extend any further aid.

Most of the firms still retain some access to capital bond markets, though with high-risk premiums. Both Consumers Power, which issued $100 million in bonds in late 1984, and Public Service of New Hampshire (PSNH), which issued $450 million in bonds in 1984, were able to sell their latest series of bonds. The concern here is whether the companies (particularly PSNH's issuance of securities with a 23 percent return on a delayed repayment plan) can eventually generate the revenues to pay back such burdensome borrowings. In PSNH's case, the company will need growth in electricity demand of 5 percent to 6 percent per year to generate enough revenue to repay its latest borrowings.[12] The primary risk here is for new investors. Utility consumers are also likely to bear the burden of repayment through rate increases.

Utilities may also form subsidiaries to carry on construction separate from the operations of the parent company. Middle South Utilities has functioned in this manner. Generally speaking, this approach can allow a utility to obtain lower-cost capital than might otherwise be available by using the parent firm's larger base of operating assets. From some utilities' perspectives, another advantage of forming subsidiaries or holding companies is that such activities are subject to regulation by the Federal Energy Regulatory Commission (which regulates interstate wholesale sales) rather than by the state regulatory commissions.[13] As shown in Table 3 in Chapter II, FERC regulation is currently considered somewhat more favorable from an investor's standpoint than most state commissions.

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[12] Robert Hildreth, *Electric Utility Financing: A View to the Future*, Energy Daily Conference (October 1984).

[13] See "Utilities Seek to Skirt State Rulings," *Wall Street Journal*, June 17, 1985. Also see *Northern States Power v. Minnesota Public Utility Commission*, Minnesota Supreme Court, January 27, 1984. One of the advantages of FERC rulemaking from the utilities' viewpoint is that they will allow up to 50 percent of CWIP to be included in the rate base.

State Assistance

In extreme cases when other nonfederal options are not effective or have not been employed, states might decide to provide special financial aid to a utility or utilities in financial trouble. Aid could take several forms, including loans or the actual purchase (with eventual leaseback of the plant to the utility) of a plant under construction. The choice of state assistance would depend largely on the available mechanisms to provide aid. Thus, a state with an independently financed power authority might have greater flexibility than a state that must seek special legislative authority to assist a private utility.

The major precedent in this area probably is the Consolidated Edison case of 11 years ago. Caught between sharply increased oil prices following the oil embargo in 1973 and a large construction program for coal- and nuclear-power plants, Con Ed omitted its first quarter common dividend in 1974. The company's bond rating and stock price plunged, and it was unable to obtain bank loans, sell its plants under construction to other utilities, or raise other sources of outside funds. In the end, the New York legislature approved the sale of the two Con Ed plants under construction to the Power Authority for the State of New York (PASNY). A loan was also considered, but eventually rejected in favor of the sale alternative, which provided the needed injection of cash for Con Ed to resolve its cash-flow problems.

Because of the speedy resolution of the Con Ed crisis, no substantial documentation exists to explain why one alternative assistance plan was considered better than another. Con Ed's financial condition, however, was much less grave than several of the utilities identified in Chapter II. The two plants involved, one coal and one nuclear, actually were good "buys" for the PASNY in that their costs had not outrun their worth. This is hardly the case with most of the troubled utilities, whose plants under construction are worth on the open market (or in a state rate case) only a fraction of the costs already incurred by the utility.

More recently, the allocation of project costs for Middle South's Grand Gulf nuclear plant among the states of Louisiana, Arkansas, and Mississippi, and the City of New Orleans has engendered proposals for government-sponsored buy-outs. 14/ Both the state of Arkansas and the city of New Orleans are considering plans to buy out Grand Gulf partners (Arkansas Power and Light and New Orleans Public Service) as a means of avoiding paying for the

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14. For a description of the Grand Gulf controversy, see *Potential Impact of the Grand Gulf Nuclear Power Plant on Small Businesses*, Hearing before the Senate Committee on Small Business, 98:2 (December 7, 1984).

high costs of the Grand Gulf project. Such actions are on hold, however, pending the final allocation of costs by the Federal Energy Regulatory Commission and the courts. 15/

THE FEDERAL ROLE IN EASING UTILITY FINANCIAL STRESS

The many ongoing and available nonfederal solutions described above appear sufficient, if employed, to relieve the short-term financial stress of troubled utilities. In some circumstances, however, utilities, state regulatory commissions, and state legislatures might fail to exercise these options fully, creating the conditions for a potential utility bankruptcy. The federal government will bear a part of any short-term financial losses through provisions of the tax code that allow such losses to be deducted from the income on which taxes must be paid. At issue, however, is whether any further federal assistance is desirable to prevent possible electricity supply shortages or severe rate increases resulting from a bankruptcy. Both adverse results are untested. Regarding the first concern, the federal bankruptcy process appears able to ensure electricity service by the utility operating through the Chapter 11 reorganization process. As to the second concern, it is not clear that electricity rates must necessarily increase after a bankruptcy. Nevertheless, the uncertain outcome of a utility bankruptcy remains a strong motivation to avoid it.

This section explores federal options--including loans, grants, or additional tax relief--to aid distressed utilities that could be threatened with bankruptcy. These options could meet the immediate cash-flow needs of distressed utilities. They would do little, however, to rectify the long-term investment concerns of the utility industry or to provide signals to consumers regarding the true resource cost of electricity.

Pros and Cons of Federal Intervention to Prevent Utility Bankruptcies

Proponents of federal intervention believe that federal assistance to utilities might be necessary, because the direct and indirect costs of a utility bankruptcy could cause economic disruption. (See box for description of federal bankruptcy process.) The magnitude of direct bankruptcy costs are

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15. The FERC issued an administrative ruling on June 13, 1985, allocating Grand Gulf costs among Middle South operating companies as follows: Arkansas Power and Light (36%), Louisiana Power and Light (14%), Mississippi Power and Light (33%), and New Orleans Public Service (17%). Middle South Utilities has recently proposed that each operating company (and its respective ratepayers) be charged one-third less than the FERC allocation. If the proposed settlement is adopted, Middle South investors would absorb a revenue loss estimated at $1.1 billion over 10 years.

THE FEDERAL BANKRUPTCY PROCESS

How likely is it that an investor-owned utility will go bankrupt? Until the Wabash Valley (an electric cooperative) declared bankruptcy in May 1985, a utility bankruptcy of any type (investor-owned or co-op) had not occurred for over 50 years. Although an investor-owned utility could itself declare bankruptcy, it is unlikely to do so until its managers have exhausted all the available options reviewed in this chapter. Instead, an investor-owned utility is likely to face bankruptcy only when its creditors force it to do so. Creditors' actions will be motivated by their perceptions of the relative cost to them of bankruptcy, compared with the cost of the continued utility operations. The creditors' actions are necessarily affected by how the state regulatory commission responds to the liquidity problems facing a distressed utility, their perceptions of demand growth, and prospects for cost recovery of plants under construction. Not all creditors, however, may be in the position of extending debt or voluntarily reducing interest payments to prevent bankruptcy. Many smaller bondholders cannot renegotiate changes in the terms of the utility's loans, and defaults may occur without the larger creditors' being able to prevent them.

A utility filing for bankruptcy (or forced to file for bankruptcy) petitions the federal bankruptcy court under Chapter 11 of the Bankruptcy Act (U.S.C. Section 1129). The federal bankruptcy judge then appoints committees to represent different classes of creditors--preferred stockholders, secured and unsecured bondholders, and common stockholders. A court appointed utility representative (the trustee) presents a reorganization plan to the court within a specified time period. The trustee also operates the company during the reorganization period to assure both continued electricity service and electricity sales revenues. This trustee is obligated to protect the rights of the creditors, not the consumers or taxpayers. The plan must discuss disposition of all property contemplated mergers or consolidation with other public or private utilities, disposition of debts, and outstanding securities.

If creditor committees can agree on a reorganization plan, each class of creditors reviews the plan. A class of creditors is judged to have approved the plan if a majority of individuals in a class deem it acceptable and credit holders owning two-thirds of the dollar amount of each class accept the plan.

If one or more classes do not approve the reorganization, the court is required to provide a "fair and equitable" solution. A fair and equitable plan usually means that creditors have been paid "all they could reasonably expect given the circumstances." The plan must give priority to secured bondholders, followed by unsecured bondholders, preferred and common stockholders, in that order. Consumers may or may not directly play a role in the reorganization, although the state regulators have to approve rate adjustments, and sales and/or mergers. (The important role played by regulation is the major difference between the bankruptcy process for electric utilities and non-regulated corporations.) If no acceptable reorganization plan can be developed, the trustee could choose to initiate Chapter 7 liquidation proceedings. Liquidation of assets is an unlikely possibility, however, for a major utility with a large service area that cannot easily be replaced by another utility.

difficult to estimate, however, apart from the high litigation costs likely to be experienced in the reorganization process.[16] Two recent studies of the effects of a potential bankruptcy examined one utility, Public Service of Indiana. The studies suggest that rate increases borne by consumers would be higher if bankruptcy occurred, primarily because of two assumptions: that the costs of refinancing would be higher to the post-bankruptcy firm, and that these costs would be borne strictly by consumers through electricity price rises.[17] This outcome might not occur, however, if the state regulators denied full rate increases and creditors were forced to absorb some of the economic losses of bankruptcy.

Proponents of federal intervention also believe that a utility bankruptcy could produce severe regional economic losses and potentially lead to a chain of bankruptcy petitions by other utilities in financial distress. Moreover, indirect bankruptcy losses could be shared nationwide by investors and creditors, resulting in costs that exceed the benefits of weeding out inefficient firms and, presumably, reducing overall income subject to federal taxation. Federal assistance could, therefore, be justified by economic disruption or national security reasons--as in the $1.5 billion federal loan guarantee to Chrysler Corporation in 1979 or the $250 million loan to Lockheed in 1971.[18] Finally, advocates of federal assistance note that a utility bankruptcy could have severe long-term consequences, by reducing the ability (or willingness) of the industry to raise capital for large, baseload plants when they are needed.

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[16] Legal costs arising from the Washington Public Power Supply System default, for example, could approach $250 million. See "The High Costs of Suing--Or Being Sued By--WPPSS," *Credit Markets*, July 1, 1985.

[17] See Congressional Research Service, "Utility Bankruptcy: Thinking the Unthinkable?"; and David Lantz, "Paying for Marble Hill: How the Bankruptcy of PSI Could Affect Indiana's Economic Development" (Hoosiers for Economic Development February 1985).

[18] None of these cases offer an exact analogy for utilities, however. The loan guarantee granted to the Chrysler Corporation in 1979 was directed primarily at preventing the potential loss of 140,000 to 400,000 jobs. In that case, the company argued successfully that the psychological impact of a bankruptcy declaration would erode consumer confidence in the long-term ability of the company to service its products, leading to near total loss of market share and liquidation of the company and its dealer network. Unlike Chrysler, utilities (as monopolies) would not risk losing their market shares during the reorganization period. See *Chrysler Corporation Loan Guarantee Act of 1979*, House Report No. 96-690 (December 6, 1979). After Penn Central and seven other northeastern railroads went bankrupt in 1970, the federal government formed a publicly owned railroad system in order to maintain freight and commuter service and prevent economic disruption. Eventually the federal government reimbursed previous creditors of these bankrupt rail systems under terms set by the special bankruptcy court. Similarly, the federal government came to the aid of the financially strapped Lockheed Corporation in 1971 to prevent the collapse of an industry deemed essential to national security. Finally, the federal government, through the Federal Deposit Insurance Corporation, took over the assets of the Continental Bank of Chicago--absorbing as much as $3.8 billion in potential losses in bad loans--to protect the depositors and prevent widespread disruption in the financial community. See CBO, *The Budgetary Status of the Federal Reserve System* (February 1985).

Assuming that a utility bankruptcy would not affect public health and safety through widespread disruptions in electricity supply, the only other condition that would warrant special federal relief to individual utilities is the threat of economic disruption. But according to available evidence the adverse economic effects of a bankruptcy probably would be small. Current financial problems are limited to the small group of firms that have experienced construction difficulties in recent years. These utilities' low stock prices and bond ratings indicate that national markets have already responded to the higher risks of investing in such firms. National investor markets would therefore be relatively unaffected if one of these companies were forced into bankruptcy. Bankruptcy effects on consumers--which would also influence regional economic activity--also appear limited since investors would bear most of the loss.

Further, the prospect of federal aid could lead to less efficiency if state regulators and electric utilities believed they could pass on local losses to the nation at large. This would reduce incentives to minimize losses and to work out their distribution in a manner generally seen as fair. Also, any precedent established for federal assistance would have to be applied throughout the utility industry, possibly leading to greater federal deficits at a time when the intent of Congress is to reduce them.

In addition, aiding the few utilities that have had construction difficulties would be discriminatory, because most utilities have built their own generating capacity without special assistance. In the long run, a policy of intervention would artificially reduce the costs of excess generating capacity, thus distorting the economic signals to both the buyers and the sellers of electricity.

Federal Options to Aid Cash Flow in Distressed Utilities

If distributional considerations do warrant intervention, the options with the greatest applicability to improve utilities' problems with short-term cash flow include loans, loan guarantees, direct grants, and selective tax relief. These measures could relieve current financial problems but would do little to discourage inefficient future investment, since they would relieve today's excess costs without addressing the problems behind them. Direct aid, for example, would not correct the causes of construction cost overruns.

Subsidized Loans, Guarantees, and Grants. Loans or grants to assist distressed electric utilities include:

- Providing low interest loans or loan guarantees at rates higher than the Rural Electrification Administration's current rate of 5 percent, but presumably lower than the going market rate; and
- Providing grants to utilities in financial distress in order to allay fears about the long-term supply of electricity. Such grants, for example, could take the form of electricity price supports to increase the utilities' rate of return.

The ultimate costs of such federal subsidies would vary with the number of utilities made eligible for benefits and the length of support. (The costs of completing just the nuclear plants under construction by the 15 distressed utilities discussed in Chapter II would be about $11 billion while the purchase of all plants now under construction would cost about $120 billion.) In the short term, these federal options could provide important relief for the current difficulties of troubled utilities. Firm-specific assistance, however, would effectively penalize those companies that succeeded in constructing facilities and maintaining normal operations without subsidies. By subsidizing these overly expensive plant investments, federal loans or loan guarantees could encourage inefficient future utility investments.

Identifying the proper subset of utilities to assist would also be difficult. Some believe that the sole precondition for federal intervention should be an actual bankruptcy declaration, so as to limit assistance to companies that had truly run out of financial alternatives. Unfortunately, significant financial and legal damages would accrue if federal assistance was withheld until this stage. As an alternative, objective "distress criteria" could be used to target utilities meriting federal assistance before an actual Chapter 11 bankruptcy occurred. The Federal Energy Regulatory Commission proposed a financial distress test in 1983 as a precondition for the commission's granting construction expenditures in the rate base. To qualify for consideration utilities had to have a bond rating of BBB or lower from Standards and Poors or Baa or lower from Moody's. 19/

Tax Relief. For many years, utilities have received significant federal tax benefits such as the accelerated depreciation and investment tax credit,

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19. The Commission also proposed alternative indicators of financial distress: quality of earnings (ratio of cash income to total income) and interest coverage (ratio of earnings to interest payments). See FERC Order 555 (July 1983) and Congressional Research Service Commission on Energy Report (June 1982).

designed to encourage capital investment.[20] Nevertheless--in recognition of the highly capital-intensive nature of the industry--additional tax relief could provide some needed liquidity for utilities suffering from cash-flow difficulties. It would, however, provide a windfall for other, more financially successful utilities.

In general, additional tax deductions or credits would be of little use to the most distressed utilities, since many have already accumulated large tax benefits which they are unable to use (such as unused investment tax credits) or lack sufficient pretax profits with which to use additional deductions. For example, the average federal effective tax rates are relatively low for most of the troubled utilities (see Table 5). Only Middle South, Ohio Edison, Public Service of New Hampshire, and Toledo Edison paid more than 10 percent in the 1982-1983 period.

Allowing utilities to sell their unused tax credits or borrow against them to increase cash flow could aid many of the troubled firms. Although the utility industry as a whole made extensive use of the investment tax credit (ITC) provision in the past (the estimated revenue loss to the U.S. Treasury was $2.3 billion in 1983), this provision is now of limited worth to many of the distressed utilities because the available credits more than offset pretax profits. Of the $3.6 billion worth of unused ITCs available to the electric utility industry at the end of 1983, almost $1 billion was held by the distressed utilities (see Table 6). Without sufficient pretax profits, however, such tax credits cannot be used until sometime in the future when profitability resumes and tax write-offs are needed.[21] Options that allow utilities to use these benefits more quickly could provide short-term help to certain companies like Consumers Power. Two such alternatives include selective safe harbor leasing and a reinvestment credit program.

Selective safe harbor leasing would allow utilities to sell some of their tax benefits to other corporations through partial sale of property. In turn, through a leasing arrangement, the utilities could still operate the plant.

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[20] Like other businesses, utilities are allowed a 10 percent investment tax credit on new plants and machinery and tax deductions for plant and equipment depreciation. Some tax provisions apply only to utilities, however, such as the provision in the Economic Recovery Tax Act of 1981 allowing utility shareholders to defer federal income taxes by reinvesting dividends.

[21] For example, Consumers Power had accumulated $263 million in unused investment tax credits by the end of 1982, but the company was unable to use these credits as an offset to its federal income tax liability in that year because its effective tax rate was already less than zero without these ITCs. As a result, Consumers Power accumulated even more unused ITCs in 1983 (for a total of $340 million).

TABLE 5. AVERAGE FEDERAL BOOK INCOME TAX RATES, 1982-1983 (In percents) a/

Company	1982 Average Federal Tax Rate	1983 Average Federal Tax Rate
Central Maine	0.3	1.9
Consumers Power	-1.7	0.6
Dayton P&L	7.8	8.5
Gulf States	1.9	2.0
Kansas City Power & Light	0.6	1.6
Kansas Gas & Electric	0.6	0.9
Long Island Lighting Company	0.6	b/
Middle South	15.8	15.3
Ohio Edison	10.3	11.2
Philadelphia Electric	9.8	6.9
Public Service of Indiana	0.7	1.2
Public Service of New Hampshire	14.4	12.9
Toledo Edison	9.7	11.1
Union Electric	2.0	1.1
United Illuminating	8.1	9.4
Industry Average (137 Major Utilities)	7.9	7.0

SOURCE: Congressional Budget Office, based on data from Standard and Poors Co., *Utility Compustat II*.

a. Computed rates based on method proposed by Donald J. Kiefer, "The Diminishing Federal Income Tax Burden on Public Utilities: Measurement and Analysis," *National Tax Journal* (December 1980).

b. Data not available.

Such provisions would allow the transfer of utilities' unused tax benefits (such as ITCs) to more profitable companies in need of tax relief. For example, a utility could sell a small generating plant to a profitable company that would reap the tax benefits of ownership. In turn, the company would lease the property back to the utility, which would then operate the plant, thereby creating a tax benefit transferred through lease rental. At the end of the lease period, utilities would contract to buy back the leased plant for a small token amount.

TABLE 6. UTILITIES' UNUSED INVESTMENT TAX CREDITS (In millions of dollars)

Company	Calendar Year 1980	1981	1982	1983
Central Maine	4	12	16	16
Consumers Power	174	187	263	340
Dayton Power & Light	38	43	29	12
Gulf States Utilities	70	41	90	112
KC Power and Light	37	28	35	32
Kansas Gas and Electric	44	60	79	88
Long Island Lighting Company	77	82	75	66
Middle South	291	389	503	581
Ohio Edison	83	91	98	63
Philadelphia Electric	45	53	19	140
Public Service of Indiana	N.A.	19	40	39
Public Service of New Hampshire	30	38	58	78
Toledo Edison	52	54	40	33
United Illuminating	20	20	14	14
Union Electric	N.A.	N.A.	79	90

SOURCE: Congressional Budget Office, based on Compustat II (Standard and Poors).

NOTE: N.A. = Not Available.

The use of this option for other industries has led to criticism in the past. The Congress ended an experiment with safe harbor leasing in September 1982 after $37 billion in industrial and commercial properties were leased in 1981 and 1982; utilities were the leading industry employing this benefit, representing about 10 percent of the leasing activity. 22/ This option might therefore be applied only to certain utilities to avoid large Treasury tax losses. The Congress might also consider whether a portion of such tax benefits should be immediately passed through to ratepayers, or whether the entire amount should be held by the utility itself for plant construction expenditures and so forth.

A reinvestment credit program would allow companies to receive interest free loans from the federal government based on the company's quantity of unused investment tax credits. For example, H.R. 3434, introduced in the 98th Congress, proposed the transfer of unused ITCs into reinvestment credits. Once a company declared its ITCs for this purpose, any qualified investment made by the company would be shared by the Treasury (up to 85 percent in H.R. 3434). The company would then pay back the reinvestment over a predetermined time period, yielding, in effect, a discounted federal loan through the tax system. The size of the loan, qualifying investments, and eligible industries (utilities were, in fact, to be excluded under H.R. 3434) could, of course, be varied. This option would not help many of the distressed utilities if reinvestment credits were not retroactive to facilities recently completed or still under construction, however. Further, tax options in general tend to clutter an already complicated tax code. The precedent that would be set by further special assistance to the utility industry could be applied throughout the economy, since many industries, such as airlines, have similar problems from time to time. The consequent overuse of special exemptions could lead to tax laws that do nothing well, including raising revenues.

For the 15 distressed utilities examined by CBO, use of these tax options could provide up to 10 percent of their immediate cash needs. This assumes that utilities could sell a safe harbor lease at 10 percent of plant value or that a reinvestment credit program would provide an interest free loan to the company (thus saving the company 10 percent over one year). According to this estimate, Middle South Utilities would receive the largest potential benefits--$58 million. Because the ITC program may be changed by the Congress this year, it is uncertain how these programs would affect the long-term investment profile of the industry. Considering the experience with safe harbor leasing in the past, limiting either option to short-term use (one to two years) might be advisable to avoid excessive costs to the federal government.

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22. See Joint Committee on Taxation, *Analysis of Safe Harbor Leasing* (June 14, 1982); and Margaret Riley, "Safe Harbor Leasing, 1981 and 1982," *Tax Notes* (November 21, 1983).

CHAPTER IV

ISSUES IN INVESTMENT EFFICIENCY

As discussed in the previous chapters, a few utilities have experienced economic losses arising from large construction campaigns. According to available evidence, the financial outcome in these cases probably will divide costs between ratepayers and utilities in such a way as to avoid bankruptcy but prolong their financially weakened position. The federal government will bear a portion of these losses through provisions of the tax code that allow utilities to deduct them from taxable income. But beyond this, the need for direct federal intervention is not apparent.

A better case can be made for federal concern with long-term utility investment. Such investment is less sensitive to the immediate allocation of losses than to the more general incentives provided by utility ratemaking. Utilities now are deferring new capacity investments for three reasons: current capacity is adequate; the rate of future demand growth is more uncertain than in the past; and recent regulatory decisions have challenged traditional utility assumptions about the recovery of invested capital. Many utilities have moved toward greater financial flexibility through strategies that postpone the need for new investment--principally by reducing peak load demand and by meeting small increments of demand with power purchased from utilities with excess generating capacity. This approach appears well-suited to current conditions.

Under any reasonable scenario for future demand growth, some new generating capacity eventually will be needed. This raises the central policy issue in long-term electricity supply: the ability of current regulatory incentives to encourage the mix of equipment and fuels best suited to the economic realities of the coming decades. Most of the responsibility for the economic regulation of the electric utilities rests with state authorities. A federal concern also exists, however, not only because an efficient electricity supply contributes to national economic well-being, but also because the federal government is already involved: by regulating wholesale electricity transactions and the organizational structure of the industry; by providing incentives for competition in electricity supply from outside the utility industry; and by influencing the choice of fuels used to generate power.

THE UNCERTAIN DEMAND FOR ELECTRICITY

In September 1985, the North American Electric Reliability Council (comprising representatives of the electric utility industry) published its members' 10-year forecast of growth rates in net generating capacity additions and peak demand.[1] For the nation as a whole, the electric utilities projected annual growth of electricity peak load would be about 2.7 percent a year from 1985 through 1994, although annual demand growth has averaged about 5 percent over the last two years. Considerable uncertainty persists concerning future load growth. Recent demand forecasts provided to the Congress range from 1.5 percent to 5 percent per year (see Table 7). Most analysts believe that demand growth will fall somewhere in the middle of this range, although individual utility systems may experience even greater variation.

Why is future demand growth so uncertain? First, analysts often disagree about both the future behavior of important economic determinants of demand--such as economic growth, electricity prices, and the prices of alternative fuels--and how changes in these factors, if they could be predicted, would actually affect demand. During the 1960s, for example, real disposable income generally grew at about 4 percent annually. Together with falling electricity prices, this led to demand growth of 6 percent to 7 percent per year. But during the ensuing decade, electricity prices increased threefold and real disposable income grew at only 2.7 percent per year, causing demand to grow only 2.5 percent annually. Currently, most forecasters expect modest GNP growth and decreases in real electricity prices (see Table 7). Low oil and gas prices are, therefore, expected to offset slightly the excessive costs of new nuclear power plants.

Besides these important macroeconomic factors, analysts cannot predict well the technological trends that also affect electricity demand--future industrial electricity needs, efficiency improvements in existing electric equipment and appliances, and the so-called "penetration rate" of equipment using electricity as opposed to gas.[2] Utilities' own efforts at load management may also affect future demand growth.[3] A 1983 study

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[1] North American Electric Reliability Council, *Electric Power Supply and Demand, 1985-1994* (1985).

[2] See testimony of Dr. Richard E. Rowberg, Office of Technology Assessment, before the Senate Committee on Energy and Natural Resources, July 25, 1985.

[3] Load management programs are designed to reduce the need to generate additional power from expensive plants to cover short surges (or peaks) in daily demand. By reducing peak demand--for example, by encouraging consumers to use appliances (washers, dryers, and so forth) during "off-peak" hours--the need for additional, costly plants can be lessened.

TABLE 7. ALTERNATIVE VIEWS OF THE LONG-RUN OUTLOOK FOR PEAK DEMAND GROWTH, ELECTRICITY PRICES, AND GNP GROWTH

Projection	Percent Growth in Annual Peak Demand (forecast period)	Percent Change in Electricity Price (forecast period)	Percent Growth in GNP (forecast period)
Energy Information Administration	3.2 (1985-1995)	-0.3 (1985-1995)	2.7 (1985-1995)
North American Electric Reliability Council	2.2 (1985-1994)	N.A.	N.A.
Data Resources, Inc.	2.2 (1985-1990)	4.6 (1985-1990)	N.A.
Wharton Econometric Forecasting Association	2.8 (1984-1994)	N.A.	2.8 (1984-1994)
Siegel and Sillin	4.0-5.0 (1985-1990)	-1.5 (1985-1990)	3.5-4.0 (1985-1990)
Applied Energy Services, Inc.	2.4 (1985-1990)	-1.0 (1985-1990)	2.7 (1985-1990)
Sant	1.5 (1980-2000)	1.5 (1980-2000)	2.6 (1980-200)

SOURCES: Energy Information Administration (EIA): Annual demand growth rate from Testimony of Dr. Helmut A. Merklein, before the Senate Committee on Energy and Natural Resources, July 25, 1985. Electricity price and GNP growth from EIA, *Annual Energy Outlook 1984*.

North American Electric Reliability Council: *Electric Power Supply and Demand 1985-1994*.

Data Resources, Inc.: DRI Energy Review (Spring 1985).

Wharton Econometric Forecasting Association: Testimony of Mark W. French, before the Senate Committee on Energy and Natural Resources, July 25, 1985.

Siegel and Sillin: Testimony of John Siegel and John Sillin, before the Senate Committee on Energy and Natural Resources, July 25, 1985.

Applied Energy Services, Inc. Testimony of Applied Energy Services before the Senate Committee on Energy and Natural Resources, July 13, 1985.

Sant: Testimony of William Hogan, before the Senate Committee on Energy and Natural Resources, July 23, 1985, Table 1.

NOTE: N.A. = Not available.

estimates, for example, that generating capacity of about 27 gigawatts (roughly equivalent to 27 large nuclear generating stations) that formerly would have been needed by 1992 will not have to be built because of the conservation and load management programs now in place.[4] Additional utility load management could yield further savings, because less than 1 percent of the residential load is now subject to such techniques. Extension of these methods could help reduce the need for new generation in many service areas, although the effectiveness of such programs is likely to vary widely from location to location.[5]

Implications of Uncertainty for Investment Planning

The wide range of demand forecasts presents a dilemma for utilities. High growth calls for entirely different actions from those needed if low growth occurs. Forecasters of high demand growth believe it may already be too late to prevent shortages by the early 1990s. Those who foresee more modest demand growth warn that starting to build new power plants now could lead to underused capacity or costly cancellations. Utilities were forced to cancel 97 nuclear and 75 fossil fueled plants between 1974 and 1984, in part because of overly optimistic expectations for future demand growth. Analysts predicting low growth, therefore, believe it would be wise to defer new investments in large baseload generation plants until actual demand can be more clearly seen. They note the availability of short lead-time options, such as gas turbines, that provide a "safety valve" in case of an unforseen surge in demand.

Thus, because of demand uncertainty, utilities face two kinds of risk: that of adding capacity to meet demand that is not forthcoming, and that of failing to anticipate demand growth and having to meet it with equipment that is economically unsuited to the task. Both risks involve considerable cost.

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[4] See Investor Responsibility Research Center, *Generating Energy Alternatives: Conservation, Load Management and Renewable Energy at America's Electric Utilities* (1983), cited in Office of Technology Assessment, *New Electric Power Technologies for the 1990s* (1985).

[5] When considering the additional uncertainties in the retirement age of power plants, the Office of Technology Assessment has noted that this demand growth range could lead to differences in new capacity requirements in 1995 of as much as 150 gigawatts of capacity (roughly equivalent to 150 large nuclear power plants). See testimony of Dr. Richard Rowberg, July 25, 1985. Also see "How Old Are U.S. Utility Powerplants," *Electrical World* (June 1985).

If, for example, a utility today faced a plausible but uncertain peak demand forecast of 5 percent growth per year through 1995, the utility might choose to forgo building new large baseload capacity now in favor of waiting to see the outcome of demand growth, and then hastily constructing smaller and less efficient units if the demand materialized. If demand growth actually proved to be 5 percent, economic losses would result through the costs of using more expensive fuels and less efficient technologies than the baseload plant would require. But if the utility built a baseload plant to meet the high forecast and demand growth proved less than 5 percent, economic losses would arise from the carrying cost of not using the capital investment. For the utility sector as a whole, these capital-related losses could be even greater than the losses related to operating efficiency (see the following box).

The optimal investment strategy for each utility will, of course, vary according to the utility's service territory, its electricity demand characteristics, the current financial condition of the utility, its access to transmission systems, and the practices of its regulatory commission.[6] Thus, the example above does not imply that smaller units, instead of baseload plants, should always be built. Rather, it suggests that deferred investment may be the "least-cost" strategy considering the uncertainty about demand growth.

In general, utilities appear to have adopted this deferred investment approach. Construction activity is at its lowest level in more than 20 years despite almost 5 percent demand growth over the 1983-1984 period. Two factors explain this strategy. First, current generating capacity is ample and should remain so in all regions through 1992. For the nation as a whole, reserve margins are above 35 percent, or about 50 percent higher than a decade ago (see following box). National average reserve margins are expected to remain above 25 percent in most forecasts through at least 1995 (see Figure 2).[7] The Energy Information Administration, for example, does not project national average reserve margins to fall below 23 percent until 1993, although some regions could have reserve margins between 20 percent to 27 percent after 1990.[8] Demand would have to grow at greater than 3 percent annually from 1983 to 1993 before the reserve

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6. See, for example, E. Cazalet and others, "Costs and Benefits of Over/Under Capacity in Electric Power System Planning," *Electric Power Research Institute*, EA-927 (1978).

7. A 15 percent to 20 percent reserve margin is generally considered prudent.

8. A recent DOE staff report also does not foresee any capacity or reliability problems in any region through 1994. See Department of Energy, *Staff Report--Electric Power Supply and Demand for the Contiguous United States 1988-1994*, DOE/IE-003/1 (May 1985), p.4.

THE RISKS OF OVERBUILDING

The utility industry is just emerging from a 15-year period of profound change, during which over 160 baseload plants were abandoned or cancelled because demand growth did not materialize as expected. (Demand growth in the 1970s was only 2.5 percent annually compared with the 7 percent annual growth experienced in the 1960s.) The industry currently possesses substantial excess capacity, and an increase in demand above the anticipated level of 2.7 percent per year would require new capacity additions only after 1990. In light of the high capital costs of new baseload plants and recent regulatory decisions that have limited some utility's cost recovery of plants deemed as "excess capacity," legitimate concern exists about the willingness of utilities to meet higher demand growth *if it occurs*. For these reasons, the costs of investing now to meet a high demand that again might not materialize appears greater than the costs of meeting unexpectedly high demand when it actually occurs with quick-to-build, but expensive-to-operate peaking capacity having a low capital cost.

Consider two cases. In one, utilities decide today that future growth will be 5 percent per year through the 1980s, instead of the 2.7 percent they had recently predicted. To meet expected shortfalls, utilities could begin construction of substantial new capacity (93 gigawatts) in 1986 to enter service in 1993. If demand materialized, industry revenues would grow to meet the added costs without changes in electricity prices. If the added demand did not materialize, however, utilities would have added new capacity eight years sooner than necessary, incurring between $39 billion and $47 billion (in discounted 1984 dollars) in unnecessary carrying costs. (Demand growth below 2.7 percent would delay the need for these plants even longer, thus raising the costs of guessing wrong.)

On the other hand, if the utilities did not change their current building plans and demand did grow at 5 percent per year, power shortfalls in the 1990-1995 period would have to be made up by peaking units that can be built more quickly than new baseload plants. (Building of these plants is assumed to begin after four years of the 5 percent trend). The costs of guessing wrong in this case would be between $31 billion and $41 billion (in discounted 1984 dollars), assuming a rather high 4 cents per kilowatt-hour difference between the cost of using peaking units rather than baseload plants to generate electricity. Although this cost is high, it remains below that of building the larger, more efficient plants and then experiencing lower than expected demand growth.

Two caveats apply to this analysis. First, it is intended to illustrate the magnitude of the costs involved rather than to forecast future events. Second, it says nothing about who bears these costs. Under current regulatory practice, the utilities tend to bear the costs of overcapacity while the ratepayers tend to bear the costs of inefficiency.

RESERVE MARGINS AS INDICATORS OF SYSTEM RELIABILITY

Reserve margins indicate the reliability of power supplies. They generally represent the difference between system capacity and peak demand, expressed as a percentage of peak demand. Disagreement exists concerning their use as a criterion to determine excess capacity, however. Questions have also arisen about the use of reserve margins as indicators of reliability, given the inordinately long construction periods needed for additions to baseload capacity.

One of two approaches to measure reserve margins are typically taken, each of which treats capacity somewhat differently. The first and most commonly used method is to treat capacity as installed (or "nameplate") capacity. This method is referred to as Planned or Installed Reserve Margins. Over the last decade Installed Reserve Margins at the regional level have ranged between 15 and 38 percent, with 20 percent considered reasonably adequate. The second method is to define capacity only in terms of that capacity that is currently or likely to be available during peak load demand periods. This second type of calculation is called the Available Reserve Margins method. Available capacity is always less than installed capacity and it includes adjustments for outages, deratings, and maintenance. Thus, Available Reserve Margins are always smaller than Installed Reserve Margins; historically these have ranged from about 5 percent to 20 percent. [1]

Critics of the Installed Reserve Margins measure argue that installed capacity overestimates capacity actually available. Critics of the Available Reserve Margins method argue that available capacity understates capacity actually available during peak loads by failing to account for regional electricity exchanges and better maintenance scheduling.

The debate over which indicator ought to be used unfortunately ignores the fact that no indicator ought to be used solely to determine if the system is reliable. Moreover, the optimal size for either Installed or Available Reserve Margins will differ by utility and region. [2] Differences in demand characteristics, such as volatility and growth, transmission capacity and number of interconnections, and costs of maintaining "backup" capacity will affect the "optimal" reserve margin, regardless of how it is calculated.

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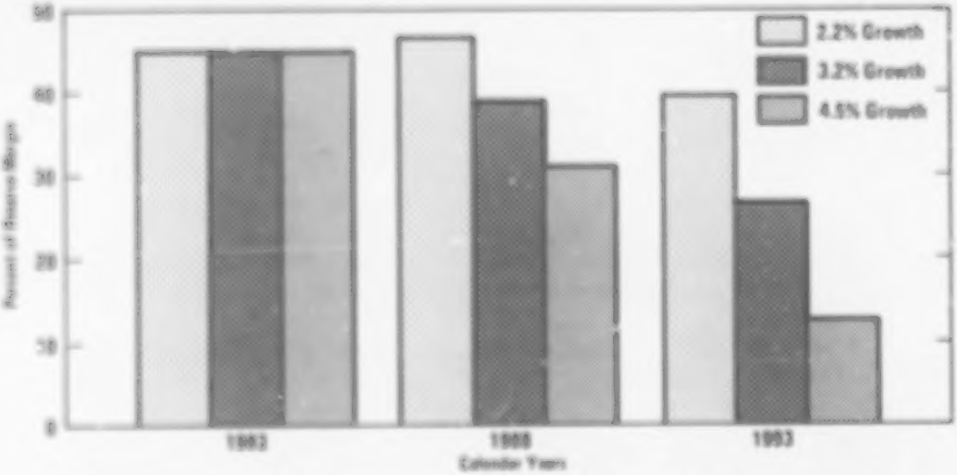
1. Department of Energy, *Staff Report--Electric Power Supply and Demand.*

2. Examples of how "optimal" reserve margins may differ by individual utility can be found in the sensitivity analyses conducted using the Electric Power Research Institute's "Over/Under Capacity Model." See also Electric Power Research Institute, "Generating Capacity in the U.S. Electric Utilities: An Update," EA-3913-SR (1984); and North American Electric Reliability Council, *An Overview of Reliability Criteria* (December 1982), to find examples of regional differences.

Figure 2.
Electricity Capacity Reserves Under Alternate Scenarios for Demand Growth



SOURCE: Congressional Budget Office based on the following forecasts of demand growth: North American Electric Reliability Council—2.2 percent; Energy Information Administration—3.2 percent; and Siegel and Sillin—4.5 percent.

margin would fall below 20 percent. Second, any utility that begins a new construction campaign probably will incur high capital costs because investors now favor companies that have completed large-scale construction projects and penalize those still involved in construction, especially of nuclear power plants. 9/

Risks of Physical Shortages

Some analysts have raised the possibility that deferred investments now could lead to physical shortages of electricity in the future. 10/ But, even if

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9. See Douglas Randall, Standard and Poors Corporation, Summary Remarks to Senate Committee on Energy and Natural Resources, July 25, 1985.

10. See, for example, K.C. Studness, "Why a Shortage of Electric Generating Capacity is All But Inescapable," *Public Utilities Fortnightly (August 1985).*

demand does grow faster than most forecasters expect, it can be misleading to infer future shortages of electricity simply by comparing generating capacity now in place with a high demand scenario. Utilities have many options that can both meet future power needs and serve the utilities' stated financial objective of minimizing the capital they have at risk. These options include: extending the life of current power plants; adding smaller, conventional power plants, such as combustion turbines, that can be built quickly; adding smaller baseload plants, perhaps 500 megawatts or less; encouraging further conservation by customers; and purchasing power from cogenerators or neighboring utilities.[11] Table 8 shows the approximate annual average cost of these options. In addition, highly efficient, modular units employing emerging technologies will become increasingly available, although widespread deployment appears unlikely in this century.[12][13]

But if physical shortages are not an issue, the incentives for utility managements to select a least costly strategy is. The task of economic regulation is to allow utilities to base investments on their economic and technical merits, rewarding sound choices and penalizing poor ones. Many current practices, however, fall short of that ideal.

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[11] Hugh Holman, "The Next Generation: Capacity Planning for the 1990s," *Public Utilities Fortnightly* (September 5, 1985).

[12] Office of Technology Assessment, *New Electric Power Technologies* (July 1985).

[13] Utilities' investment options may also be significantly affected by comprehensive revisions to the federal tax code, which are now under consideration by the Congress. See, for example, *The President's Tax Proposals to the Congress for Fairness, Growth and Simplicity* (May 1985). Probably most important from the standpoint of utilities' plans for new capital investment--other than the overall uncertainty as to what demand changes will actually take place--are the Administration's proposals to repeal the investment tax credit program and to adopt a new capital cost recovery system. On balance, it appears that the President's plan could make future utility investment in new generating plants more attractive than at present, primarily because the President's plan would lower the current corporate tax rate from 46 percent to 33 percent. Specific changes could severely affect individual firms, however, depending on their individual tax position and the nature of the change. For example, utilities that had claimed large depreciation writeoffs over the last five years could be forced to pay a special windfall recapture tax under the President's proposal. See "Tax Plan: Smokestack View," *New York Times*, July 2, 1985. In addition, the Administration is also proposing changes in the accounting treatment of investment tax credits that could benefit ratepayers. See "Billions At Stake in Tax Dispute," *Energy Daily*, September 4, 1985. Both of these proposals could strain a company's short-term cash flow in some cases.

TABLE 8. COSTS OF SUPPLYING ELECTRICITY, BY TECHNOLOGY OPTION (In 1984 dollars)

Electricity Source	Cost (cents per kwh)
Baseload Plant [a]	
Coal Fired (500 megawatts)	4.23
Peaking Units [a]	
Natural Gas-Combined Cycle (250 Mw)	4.85-6.25
Natural Gas-Combustion Turbine (75 Mw)	6.85-7.56
Resid Fired-Combined Cycle (250 Mw)	5.70-7.34
Cogeneration [b]	4.0-7.0
Upgrade of Existing Plant [c]	2.0-6.7
Purchased Electricity [d]	2.0-7.0

SOURCE: Congressional Budget Office.

a. Capital, operating and maintenance costs from Electric Power Research Institute (EPRI), *Technical Assessment Guide*. Exhibit App. B4-4b, BH-16b, B4-18b all for the East/West Central regions (Palo Alto, Calif: EPRI, May 1982). Fuel prices from Energy Information Administration, *Annual Energy Outlook 1984*, Tables 16, 17, 18 (January 1985). Price spread for peaking units results from number of years for capital recovery. Lower cost is for capital recovery over 20 years. Higher cost is for capital recovery over five years, and in which case a utility plans to have baseload capacity coming on line at the end of that time period.

b. See "States' Cogeneration Rate-Setting Under PURPA, Part 4," *Energy User News*, Vol. 9, No. 40-43 (October 1984).

c. Costs are highly project specific. See Office of Technology Assessment, *New Electric Power Technologies* (July 1985), Chapter 5.

d. Energy Information Administration, *Financial Statistics of Selected Electric Utilities in the United States*. The large spread reflects cost differentials in excess power availability stemming from geography, current reserves, month of sales, and so forth.

REGULATORY ISSUES IN INVESTMENT CHOICE

About 70 percent of the electricity in the United States is supplied by privately owned utilities.[14] These firms are franchised monopolies, legally obligated to provide electric energy to specific territories. To meet demand growth, they must build new plants, and to build plants they must raise large amounts of capital from earnings, stock sales, and the bond markets. This has made electric power one of the most capital intensive industries in the United States, accounting for 20 percent of all industrial capital investment, one-third of all corporate financing, and one-half of all new common stock issuances.[15] It also implies, however, that the regulatory treatment of capital investment is the salient long-term issue for the electric power industry and its customers.

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[14] Most of the remaining electricity is generated by a number of publicly owned enterprises consisting of six federal power systems, 900 rural cooperatives, and 2,200 municipal, state, and regional power authorities.

Interstate transactions for wholesale electricity, about a third of all electric utility sales, are regulated by the Federal Energy Regulatory Commission (FERC). But the bulk of electricity transactions are retail sales of electricity, and these are regulated by state public utility commissions. The major concerns of each state commission are to assure that ratepayers are given reliable service at "just and reasonable" rates and that utilities providing such service are allowed returns adequate to attract capital. The commissions accomplish these goals through rate regulation.

The Hope Decision

Current state and federal ratemaking practice is based largely on the Supreme Court's Hope Natural Gas case of 1944.[16] The court's decision essentially set forth three principles that guide state regulation:

- Investors in utilities should earn a return comparable with that earned in other businesses with similar risks and uncertainties;
- The allowed return should ensure the financial integrity of investments in a utility; and
- The allowed return should be sufficient to attract the necessary capital for future construction projects.

The Hope decision became the precedent that state regulators follow in assessing adequate revenue requirements for utilities in their jurisdictions. But it established no precise formula for doing so. Under the Hope criteria, utility revenues are considered adequate when revenues from electricity sales cover the cost of providing electricity plus a "fair" rate of return on the value of the utility's assets (the rate base). It did not matter to the court whether a utility earned a low return on a high capital base, or a high return on a small base, as long as these principles were upheld. As a result, state regulators now have considerable discretion with regard to the actual procedures used to determine rates.

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[15] Scott Fenn, *America's Electric Utilities: Under Siege and In Transition* (New York, N.Y.: Praeger, 1984).

[16] *Federal Power Commission* v. *Hope Natural Gas Co.*, 320 U.S. 591 (1944).

Two closely related concerns have dominated current thinking about the regulatory treatment of utility capital investments. The first is the treatment of the capital that is committed during the lengthy construction of a modern power plant. Allowing the utility to charge ratepayers for all or a major portion of these committed funds would improve cash flows significantly and reduce the business risk of major projects. On the other hand, it might reduce incentives for construction efficiency and the consideration of less capital-intensive alternatives.

The second concern is the bearing of risks and rewards. A utility's legal obligation to provide electricity service for its area creates strong pressures to assure generating capacity. Constructing a plant that is both timely and cost-effective can provide significant savings to customers, without necessarily providing the utility greater profits. On the other hand, overbuilding to meet a forecast demand that does not materialize produces surplus capacity. Either electricity customers must pay for this capacity they cannot use immediately, or the utility and its investors must assume the costs. The division of these risks and rewards between the utility and its customers is a major regulatory issue.

Charging for Construction Work in Progress

A central question in electricity ratemaking is the treatment of plants under construction--namely, when charges should be included in electricity rates and how high they should be. Each state utility commission treats the recovery of new plant investment differently. About half the states have, on occasion, incorporated a portion of the construction work in progress (CWIP) into the rate base. This treatment allows utilities to recover part of the costs of CWIP before the plant becomes used and useful.

When CWIP is not allowed in the rate base, state regulators generally provide an "allowance for funds used during construction" (AFUDC). As most widely applied, AFUDC is an accounting method for treating the financing costs of plants under construction and deferring those costs until the plant is completed and entered in the rate base. Under AFUDC, construction expenditures for plants not yet in service are set aside in a special account which is listed as an asset on the balance sheet. This account is merely a tabulation of the accruals allowed for return of capital expenditures. This "asset" earns an allowed return just as any other utility rate base property, but the calculated return is not realized as cash income by the utility until the facility is placed in service. Until then, the utility must maintain its cash flow in other ways, often by issuing debt.

To the extent that an AFUDC account is used to defer the return on invested capital, the utilities' shareholders bear the risks of lower than expected demand, delays in power plant completion, and cost overruns. This practice can lead to several difficulties for utilities. First, electricity consumers are initially shielded from one price effect of their consumption--the need for new capacity--and later presented with sharp rate increses. At the same time, the utility's ability to make additional investments is constrained by cash-flow limitations and the recognition by investors that business risk has been increased by the lower quality of earnings. Finally, if the demand for electricity proves to be less than forecast when the plant was begun, the utility may be required to bear the carrying costs of the excess capacity until it becomes used and useful. (The differences between AFUDC and CWIP ratemaking are discussed at greater length in Appendix A.)

Sharing of Risk and Reward

In contrast with capital costs, the fuel costs of producing electricity are recovered quickly in most states, often through "fuel adjustment clauses." These allow all or part of increases in fuel prices occurring between rate hearings to be recouped, usually with minimal delay, in order to ensure enough cash flow to purchase fuel. Thus, ratepayers usually bear the risks of higher electricity costs caused by fuel price increases, and stockholders generally bear the risk that some portion of their invested capital will be lost or earn less than the anticipated return.

Beyond these general tendencies in assignment of risk, however, utilities face considerable uncertainty regarding the treatment of capital charges, as few states have firm standards for rate treatment of CWIP. For completed plants, many state commissions are reinterpreting the used and useful standard of plant cost recovery to require that a new plant is actually used to meet current demand and is not simply operational. 17/

Such decisions lend credence to utilities' claims that they face an "assymmetry of risk" in the present regulatory environment. In this view, state regulators pass on to ratepayers the savings achieved when utility management makes the right decisions, but are not as willing to pass on cost increases for construction efforts rendered unnecessary because of changing demand conditions. Indeed, many utilities have stated they will not build new baseload plants, regardless of demand, until these regulatory conditions change. 18/

Not all the efforts of regulators to shield consumers from extreme price increases have been financially detrimental to utilities, however. Indeed, many utilities have proposed that rate commissions not enter the entire cost of a completed plant into the rate base at once, but rather phase it in over several years to allow customers a period of adjustment to the higher prices. Although this delays the cash return on investment, it does not necessarily eliminate it, because the unincluded portion of the plant's cost continues to earn an AFUDC return until it enters the rate base.

Similarly, most current practices do not represent a marked departure from the rules under which regulators and utilities have always operated. Recent rate base disallowances of imprudently incurred costs--such as the New York commission's $1.5 billion disallowance of the costs of Shoreham because of poor management oversight--are based not on a new standard but on the prudency standard that has always guided utility ratemaking. As for exclusions of excess capacity from the rate base, some state officials note that utilities are responsible for monitoring demand changes at each stage of construction to ascertain the least expensive method of meeting future load. Thus, if demand conditions change, the prudent utility would cancel construction and the reasonable regulatory commission would grant some

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17. The most extreme form of this type of judgment was the Colstrip case, in which the Montana Public Service Commission denied the Montana Power Company any rate relief for a completed coal-fired plant, asserting that the used and useful criterion is met only if the plant is needed at the time it goes into service. See *In the Matter of the Application by the Montana Power Company for Authority to Establish Increased Rates*, Montana PSC Order No. 5051C, August 3, 1984. The Montana Supreme Court, however, later reversed this decision on the grounds that the regulatory standards were changed after the plant was completed.

18. See, for example, Statement of Keith Turley, Chairman of the Board, Arizona Public Service Company, before the Senate Committee on Energy and Natural Resources, July 23, 1985.

recovery of the utility's sunk costs. The problem for utility management, however, is the after-the-fact determination by regulators that the utilities should have foreseen events that were clearly beyond the scope of any forecasting method.

CONCLUSION

In light of the nationwide abundance of generating capacity and the considerable uncertainty that surrounds future demand, the strategy of financial flexibility now preferred by most utilities has much to recommend it. Of greater concern, however, is whether the incentives provided by current rate-base regulation are likely to lead to an efficient mix of capital investment and fuels once demand growth necessitates new generating capacity. While current practices are likely to result in widespread electricity shortages, the nation's electricity supply could become less cost-effective if regulatory incentives continue to bias utilities away from capital investments regardless of their technical or economic merit. Although state regulators have the primary responsibility for the financial incentives of the electric utility industry, the Congress might consider several options to move the electric system toward greater economic efficiency. These are discussed in Chapter V.

CHAPTER V

FEDERAL OPTIONS FOR LONG-TERM EFFICIENCY IN UTILITY INVESTMENT

The utility industry has responded to an increasingly risky business environment by adopting strategies that emphasize flexibility and limit capital exposure. While this response is unlikely to lead to widespread physical shortages of electricity, it does raise doubts about the ability of current regulatory practices at both the state and federal levels to provide incentives for the most efficient mix of generating equipment, fuel use, and conservation practices. State regulators have the greatest leverage here, but the Congress could also consider federal options to improve efficiency.

This chapter examines alternative federal policies to promote more efficient choices for utility investment. The following options are discussed:

- Establish federal ratemaking guidelines to help reduce regulatory uncertainty at the state level;
- Revise the Public Utility Holding Company Act to enable utilities to diversify their investment risks;
- Amend the Public Utility Regulatory Policies Act to allow more efficient electricity pricing and utility ownership of cogeneration facilities;
- Change federal regulatory policies and the federal tax code to promote "fuel neutrality" in utilities' investment choices; and
- Encourage efficient use of transmission facilities to allow low-cost generation to displace high-cost generation.

These changes, alone or in combination, could help restore the environment for more efficient utility investment. (These options are summarized in Table 9.) Because the federal role in utility regulation remains somewhat limited, however, appropriate state and utility action is crucial if large efficiency gains are to be realized.

TABLE 9. FEDERAL OPTIONS TO PROMOTE LONG-TERM EFFICIENCY IN UTILITY INVESTMENT

Option	Description	Relative Effectiveness of Option
Standardize Ratemaking	Would establish nonbinding regulatory guidelines for state commissions, such as staged plant construction review.	Could provide greater certainty for utilities' future power planning efforts and prospects for investment cost recovery, but would need state-initiated legal changes.
Liberalize Public Utility Holding Company Act	Would remove restrictions on utility diversification.	Could provide utility management with greater flexibility to diversify holdings that could yield ratepayer benefits, but could also lead to diversion of utility assets into riskier, nonregulated lines of business.
Change Public Utility Regulatory Policies Act	Would allow utilities to own majority interests of cogeneration facilities.	Could provide greater certainty for utilities' future power planning efforts and greater incentives for cogeneration investments by utilities, but could also reduce nonutility cogeneration investment incentives.
Promote Fuel Neutrality in Utilities' Investment Choice	Would end restrictions on natural gas use, restore equal tax depreciation periods for nuclear and coal plants.	Could allow alternative fuels to compete on a more equal basis, but certain changes could conflict with other energy policy goals, such as reducing dependence on foreign oil.
Encourage Expanded Transmission Capabilities	Would promote efforts to increase utilities' power interconnections.	Could improve power distribution efficiencies, reduce need for new generation investment; but construction of new transmission lines could incur significant costs and delays because of existing siting requirements.

SOURCE: Congressional Budget Office.

STANDARDIZE RATEMAKING PRACTICES THROUGH FEDERAL GUIDELINES

To help balance the risks and rewards of new investment, the federal government could develop nonbinding guidelines for states to follow in reviewing new plant construction. These guidelines could suggest state approaches to cost-effective investment through more balanced treatment of the risks of excess capacity and less efficient generation. For example, state regulatory commissions could consider better ways to share the responsibility for predicting demand. States could approve (or disapprove, as appropriate) plant costs at several stages in the construction process. This staged review would lower investment risk by guaranteeing eventual cost recovery of the approved portion of the project, even if these costs were not immediately included in the rate base. It would forewarn of changes in demand growth and enable the utility either to abandon construction or to mothball the plant for future use if conditions warrant. The State of Indiana has taken this approach in a law enacted in April 1985. 1/

Other guidelines might allow the utility a higher rate of return on cost-effective investments. When new capacity results in net "avoided costs," some portion of the savings could be reflected in utility earnings, thus giving these companies a direct financial stake in providing the least costly generation. 2/ In addition, incentives to improve productivity could be included in guidelines for ratemaking. For example, a utility could be guaranteed that 80 percent of input price increases could be passed to its customers. Thus, if annual input prices rose by 15 percent, the utility would be permitted to pass a 12 percent price increase along to its customers. If the utility had improved its productivity by 3 percent, its profits would not be affected. If productivity grew at less than 3 percent, the company would lose money. But if productivity rose at over 3 percent, it would increase its earnings. 3/ Of course, the precise specification of such an approach would

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1. Under Indiana Senate Act 546 (signed into law April 1985), the state commission is required to review the continuing need for a utility's project and approve past construction work at the request of the utility. If the commission then approves the construction and the cost of the portion of the facility under review, "that approval forecloses subsequent challenges to the inclusion of that portion of the facility in the public utility's rate base on the basis of excessive cost or inadequate quality control." This procedure does not apply to facilities begun before 1985, such as PSI's Marble Hill plant.

2. See, for example, M.J. Smith and W. Dickter, "Living With Standards of Performance Programs," *Public Utilities Fortnightly* (August 16, 1984); and Edison Electric Institute, *Incentive Regulation in the Electric Utility Industry* (May 1984).

3. See William J. Baumol, "Productivity Incentive Clauses and Rate Adjustment for Inflation," *Public Utilities Fortnightly* (July 22, 1982) pp. 11-18.

vary from utility to utility and from year to year. But inclusion of such concepts in regulatory practice could give additional incentives for efficient operation. Approaches such as these might better balance risk and reward in states seeking ways to give their utilities greater responsibility for the economic outcome of investment decisions.

The federal government has had little influence on state ratemaking in the past, however, and it is uncertain how much real effect voluntary guidelines could have. Voluntary guidelines could even be seen as a federal intrusion into the traditional prerogatives of state regulation, and could encounter resistance independent of their economic merit. [4] In addition, state regulatory commissions and legislatures themselves may alter many current rate practices in response to the recent difficulties caused by expensive construction programs, as discussed in Chapter II.

Suggested federal guidelines also should be designed carefully to avoid overencouragement of baseload construction relative to other alternatives, such as conservation or investment in smaller, modular facilities. [5] Indeed, utilities and their investors might still prefer the flexibility offered by lower capital cost alternatives to adding to or replacing baseload capacity, even though the cost of supplying electricity with these alternatives might be somewhat higher. Federal efforts in regulatory reform should also recognize that the costs of imprudent investment decisions must still be borne by stockholders, and that investment risks associated with normal market forces cannot be completely eliminated.

REVISE PUBLIC UTILITY HOLDING COMPANY ACT

As noted in Chapter III, mergers with other companies can be one solution to the financial troubles of a distressed utility. For the longer term, utility mergers could, in certain instances, provide greater cost efficiencies in electricity service. Some public utilities are also becoming increasingly interested in diversification into unregulated lines of business as a means of improving their overall risk profile. Provisions of the Public Utility Holding Company Act (PUHCA), however, could deter utilities from engaging in these activities. Liberalizing certain provisions of the act has, therefore, been suggested as a means to enhance the industry's long-term investment flexibility.

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4. See, for example, *FERC v. Mississippi*, 456 U.S. 742.

5. For a discussion of the potential benefits of conservation investments through end-use efficiency improvements, see Rocky Mountain Institute, *Least-Cost Electrical Services as an Alternative to the Braidwood Project*, Illinois Commerce Commission Docket #82-0855, 83-0035, July 3, 1985.

The PUHCA has three essential elements, which are administered by the Securities and Exchange Commission (SEC). First, the SEC has the power to reorganize holding company structure according to standards set forth in the act. This task is essentially accomplished. The number of registered holding companies still subject to the act has been reduced from 200 to 12 through reorganization. Of these, three are gas utilities and nine are electric, the latter owning about 20 percent of private electric utility assets; the major part of the industry is, therefore, currently exempt from the act. The SEC now focuses on its two other major responsibilities under the act: the oversight of security issuances by holding companies to ensure proper capitalization of the companies and their subsidiaries, and supervision of mergers and acquisitions by both holding companies and exempt utilities engaging in interstate mergers.

The act's regulatory jurisdiction over interstate utility mergers might discourage such mergers by companies not now subject to regulation under PUHCA. The act has limited diversification by registered holding companies subject to its provisions by disallowing certain types of acquisitions. Generally, the PUHCA limits registered holding companies to diversifying in functionally related enterprises that are reasonably incidental or economically necessary or appropriate to the operations of a utility system. Utilities now exempt from SEC regulation also view the act as a threat to their diversification activities, however, since their exempt status can be withdrawn if such status is found to be no longer in the public interest.[6]

Proponents of liberalizing the PUHCA note that reducing SEC control over utility merger and diversification activities could provide utility management with greater flexibility to diversify holdings so as to yield significant benefits to investors.[7] This flexibility is increasingly important given the slowdown in new plant construction and most utilities' improved cash-flow positions. If freed from PUHCA constraints, holding companies and exempt utilities could examine diversification alternatives and interstate mergers solely on their economic merits, rather than their regulatory implications. In addition, nonutility enterprises would no longer be discouraged from entry into the generation and transmission sector of the utility market by the PUHCA, which could add to competition in electricity supply.[8]

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[6] See Donald Dulchinos and Larry Parker, *Electric Utilities: Deregulation, Diversification, Acid Rain, Tall Stack Regulation and Electric Demand Issues*, Congressional Research Service, IB86134 (July 29, 1986).

[7] Current regulations already allow exempt utilities to create power generation subsidiaries without becoming subject to further regulation. See 17 Code of Federal Regulations 250.

[8] Similar potential advantages are cited for proposals to deregulate other aspects of the electric utility industry. See, for example, P. Joskow and R. Schmalensee, *Markets for Power: An Analysis of Electric Utility Deregulation* (Cambridge, Mass.: MIT Press, 1983).

Those opposed to liberalization argue that these changes would encourage a diversion of capital and human resources from regulated to unregulated industries, possibly exposing customers of the regulated firm to increased costs from unregulated, risky investments or liens on regulated assets. In a review criticizing SEC proposals to repeal the PUHCA, the General Accounting Office also noted that doing so would have several adverse effects:

- States would lack jurisdiction over interstate holding companies and would be ill-equipped to oversee their interstate financial transactions;
- Approval of holding company acquisitions would no longer be required;
- Approval of securities issued by holding companies would no longer be regulated by SEC; and
- Allocations of service company costs (between operating and holding companies) would no longer be regulated. [9]

The GAO therefore recommended retention of SEC's role in reviewing the $11 billion in annual securities transactions of utility holding companies.

Liberalizing the holding company legislation would also have mixed results for ratepayers. While ratepayers could potentially benefit from lower capital costs achieved through successful company diversification, utility assets could also be used to finance unregulated, riskier lines of business, and result in higher electricity rates from losses and increases in capital cost.

Many state regulators are opposed to weakening or repealing the PUHCA, for they fear that they will be unable to regulate the complex interstate operations of holding companies without SEC oversight. [10] Of particular concern is the possibility that holding companies could divert capital resources from state regulated utility operations to other, nonregulated activities, especially in the long term. But this outcome is quite uncertain, because even in the absence of PUHCA, states could still exercise considerable control over utility diversification. Other state officials suggest that the PUHCA should be strengthened, not repealed. For example, Governor Clinton of Arkansas argues that the SEC should be required to seek from state utility commissions an affirmative statement that security laws are either inapplicable to certain utility transactions or that a utility has complied with such laws. [11] This would allow state regulators to approve construction plans by holding companies if a subsidiary operated within their state.

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[9] See General Accounting Office, *Analysis of SEC's Recommendation to Repeal the Public Utility Holding Act*, RCED-83-118 (August 30, 1982).

[10] See, for example, *Public Utility Holding Company Act Amendments*, Hearing before the Subcommittee on Energy Conservation and Power and the Subcommittee on Telecommunications, Consumer Protection and Finance, House Committee on Energy and Commerce, Serial No. 98-79, October 21, 1983.

AMEND THE PUBLIC UTILITY REGULATORY POLICIES ACT

The Public Utility Regulatory Policies Act (PURPA) was passed in 1978 to encourage energy conservation and the development of alternative energy sources through changes to retail regulatory policies. Since its passage, PURPA appears to have stimulated the rapid development of customer-owned alternative power sources such as cogeneration. Cogeneration nationwide now produces at least 11,062 megawatts, and is expected to grow by another 10,000 to 50,000 megawatts by the 1990s. This added capacity may reduce the need for some utilities to build more power plants. [12] At the same time, however, PURPA's requirements that utilities must buy power from all qualifying facilities in their franchise areas (while still retaining the obligation to provide backup power to cogenerators if it is needed) have complicated utilities' efforts to plan future capacity requirements. Utilities are currently prohibited from owning the majority share of a PURPA-qualifying facility. Allowing utilities such ownership rights could yield a number of benefits, including:

- Reducing capacity planning uncertainty by allowing greater utility control over the operation of cogeneration facilities;
- Increasing deployment of small modular power generating technology, particularly cogeneration; [13] and
- Lowering customer rates.

Under current policy, ratepayers generally receive only the savings represented by the difference (if any) between the utility's avoided cost and the cogenerator's contracted selling price.[14] If, on the other hand, the utility owned the facility, ratepayers could reap the full savings to the extent that actual power production costs were less than the avoided cost level.

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[11] See *Potential Impact of the Grand Gulf Nuclear Power Plant on Small Business*, Hearing before the Senate Committee on Small Business, December 7, 1984.

[12] See Electric Power Research Institute, *1983 Utility Cogeneration Survey*, EPRI EM-3943 (April 1985); and Worldwatch Institute, *Electricity's Future: The Shift to Efficiency and Small Scale Power*, Paper #61 (November 1984). About 70 percent to 80 percent of this capacity is expected to use natural gas as a fuel source.

[13] See Office of Technology Assessment, *Industrial and Commercial Cogeneration*, OTA-E-192 (February 1983).

Nevertheless, allowing utilities to own PURPA-qualifying facilities could reduce the number of cogeneration and alternative technology power projects pursued by nonutilities.[15] Private companies could be wary of utilities controlling power production facilities inside their plants. Special regulations might also be needed to assure that utilities did not give preferred transmission access to their own cogeneration projects. Finally, the basis of state commission's determination of avoided cost levels could also change--to reflect the avoided costs of PURPA-qualifying power sources, rather than conventional baseload facilities--thereby reducing the potential profitability of non-utility PURPA projects.

PROMOTE FUEL NEUTRALITY IN UTILITIES' INVESTMENT CHOICES

A number of studies have asserted that certain federal regulatory and tax policies may distort the relative costs of alternative energy sources, leading to overall inefficiency in utilities' investment choices.[16] Removal of these policies--thus allowing alternative fuels to compete more equally--could lower the costs of electricity generation to both ratepayers and federal taxpayers. Most prominent options in this regard are ending restrictions on the use of natural gas for electricity generation, restoring equal tax depreciation periods for nuclear and coal power plant investments, and changing the tax provisions that discourage mothballing partially completed power plants when cheaper alternatives become available.

Fuel Use Restrictions. The Powerplant and Industrial Fuel Use Act, enacted during the oil and natural gas shortages of 1978, generally prohibits the construction of new generating stations fueled by oil or natural gas. The deregulation of oil and gas markets, together with the recent dramatic reductions in the price of these fuels, suggests that these prohibitions be reconsidered. The removal of the gas restrictions--either outright or through a less restrictive policy on granting exemptions in power generation applications--could yield environmental benefits, stimulate interfuel competition, and encourage utility investments based on the economics of electricity production. In addition, removal of the natural gas restrictions could also improve the deployment opportunities for certain "clean coal" and solar technologies reliant on natural gas as an interim fuel. [17] Removing the oil restriction as well would further increase interfuel competition, but would also leave the utilities and their customers more vulnerable to any future disruptions in oil supply.

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[14] Avoided costs levels--which are established by state commissions and vary depending on whether the state seeks to encourage cogeneration--generally reflect the incremental costs to a utility of generating additional power.

[15] This reduction may be more than compensated by expanded utility use of alternative energy sources. See Office of Technology Assessment, *New Electric Power Technologies* (July 1985).

[16] See, for example, Rocky Mountain Institute, *A Preliminary Assessment of Federal Energy Subsidies in FY 1984*, testimony submitted to the Subcommittee on Energy and Agricultural Taxation, Senate Finance Committee, June 21, 1985; and Congressional Budget Office, *Energy Tax Expenditures: A Compendium*, Staff Memorandum (1981).

Equal Tax Depreciation Categories. Another important federal policy that affects utility investment choices is the contrasting tax treatment of coal and nuclear power plants. Under the Accelerated Cost Recovery System (ACRS) adopted in the Economic Recovery Tax Act of 1982 (ERTA), coal power plant investments may be depreciated in 15 years, but nuclear plants have a tax life of just 10 years. Other things being equal, investing in nuclear power would, therefore, be preferable. Because ERTA's legislative history provides no specific reason for treating the two technologies differently and because both coal and nuclear power plants have relatively equal productive lifespans, amending the ACRS to eliminate this difference could help promote further fuel neutrality in utilities' investment choices. [18]

Tax Provisions for Uncompleted Plants. If demand growth proves lower than expected or less costly alternatives become available, the most economic course of action for a utility would be to cease construction of a partially completed plant. Current tax law, however, provides little incentive for utilities to mothball plants for later completion and use if needed. If a utility cancels a plant under construction, it obtains a tax write-off for a business loss. If it delays construction, however, it obtains no tax benefits. Allowing an abandonment loss deduction upon the mothballing of a plant with the repayment of tax if the plant is subsequently used, or restricting the imposition of state or local property taxes on mothballed plants could enhance this course of action. Savings from changes in the tax treatment of mothballed plants could easily be eroded, however, by the high carrying costs that would accrue by not completing the facility and entering it into the rate base.

INCREASE TRANSMISSION CAPABILITIES

Because of the excess generating capacity available in some parts of the United States, purchased power is often relatively inexpensive. Thus, many utilities that foresee a need for additional power are seeking to increase their transmission access to available power rather than risking investment in new generation facilities. 19/ Unfortunately, transmission service arrangements and capacity limitations on existing transmission lines sometimes preclude utilities from achieving the access they desire. From a national perspective, these inadequate transmission linkages lower efficiency by requiring many utilities to maintain higher reserve margins than they might otherwise need in order to ensure reliable service, especially during emergencies. Federal regulatory incentives that better allocate transmission over current lines or promote the construction of new transmission lines where these would be cost-effective might, therefore, lead to better regional or national efficiency. Substantial regulatory and physical impediments would need to be overcome, however, if such efforts were to be fully successful.

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[17] See Office of Technology Assessment, *New Electric Power Technologies* (July 1985).

[18] The President's proposed tax reform plan would, in fact, equalize the depreciation period for coal and nuclear plants. The plan would also increase, however, the depreciation period of smaller-scale generation plants to 10 years. Since the actual economic lives for smaller-scale facilities are considerably less than those of coal or nuclear plants, this change could discourage investment in these types of facilities, other things being equal.

The National Electric Reliability Council (NERC) has identified a number of transfer areas that could benefit from new interconnections, such as the Pacific Northwest/California, Southwest/California, and Canada/Northeast. Physical limitations may limit the overall net benefits, however. 20/ Moreover, without direct financial assistance (which would be extremely expensive) or an override of existing state authorities, federal powers to promote construction of new transmission lines are rather limited. Utilities constructing new lines are first subject to state laws applicable to siting and environmental protection. These regulations may inhibit new line construction especially if more than one states' requirements must be satisfied. Though the FERC may exempt electric utilities from any provision of state law "if the Commission determines that such voluntary coordination is designed to obtain economical utilization of facilities and resources in any area," doing so would risk severe political opposition. 21/ Nor is it clear that federal authority can override state siting laws. Finally, the evidence indicates that utilities are pursuing new line construction without explicit

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19. The demand for wheeled electricity (transmission services provided by a utility on a prearranged basis to deliver power generated outside its own system to the system of another utility) has in fact increased more than 10 times in the last 20 years, and recent utility surveys confirm that this trend is likely to continue. Los Alamos National Laboratory, "The Future Market for Electric Generating Capacity: Technical Documentation," LA-10285-MS (March 1985); D. Bauer "An Investor-Owned Utility Perspective on Intersystem Energy Transfers and Wheeling Issues," Edison Electric Institute's presentation to National Association of Regulatory Utility Commissioners, (November 1984); Electric Edison Institute, "Transmission Access and Utilization Briefing Papers," (December 1984).

20. For example, recent Canadian power imports in the Northeast have adversely affected transmission readings as far south as the Carolinas and Virginia. See D. Bauer, "An Investor Owned Utility Perspective on Intersystem Energy Transfers & Wheeling Issue" Edison Electric Institute, November 27, 1984.

21. M. Cohen, "Efficiency and Competition in the Electric Power Industry," *Yale Law Journal* (1979).

support; fully 40 percent of planned utility investment, in fact, is now slated for transmission. Recognizing these problems and limitations, the FERC has instead issued a Notice of Inquiry to consider changing its regulatory policies in the long term. 22/

Federal efforts to equalize utility access to existing transmission lines would also have mixed effects on system efficiency. The FERC is not currently authorized under the Federal Power Act of 1935 to order a utility selling power in interstate commerce to interconnect with another firm, or to sell or exchange power with another utility. Without this authority, smaller utilities have felt that they lacked the leverage to participate in the regional economies of scale attained by the larger utilities forming power pools. To solve this access problem, it has been proposed that the Congress grant FERC the power to compel power transfers (known as "wheeling"). Mandatory transfers would enable any distributor to purchase power from any producer within economical transmission distance. It would facilitate reserve sharing and the exchange of economic energy and peak capacity reserves between systems that are not now interconnected.

Unfortunately, mandatory transfers would not encourage new investments in transmission lines, but merely reallocate the benefits derived from existing power transfers. Mandatory transfers could also make it difficult to plan future power system needs, and some cases diminish system efficiency because compelled linkages could affect the physical performances of existing transmission arrangements. And finally, utilities themselves have opposed mandatory wheeling. Their basic concern is the loss of their large, industrial customers, who would purchase their electricity generated by another system but still enjoy the security afforded by their utility's obligation to serve them on demand. In addition, utilities cite the complex planning and operational problems that could arise under any sort of common carrier scheme. 23/

Alternatively, the Congress could authorize the creation of regional power planning compacts to increase transfers in the industry. Such an approach would allow states to develop joint demand-supply forecasts and electricity import and export agreements. These agreements could also help eliminate inconsistencies among neighboring states' regulatory policies. Certain proposals, such as H.R. 3074, would also permit the regional compact to apply to the Federal Energy Regulatory Commission for an order to compel one or more electric utilities to provide or modify transmission services to meet regional requirements. 24/ The new regional planning enti-

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22. U.S. Federal Energy Regulatory Commission, "Regulation and Electricity Sales--for Resale and Transmission Service," Docket No. RM85-17-000, Phases I and II (May 30, 1985).

23. Jerry Pfeffer, "Policies Governing Transmission Access and Pricing: The Wheeling Debate Revisited," *Public Utilities Fortnightly* (October 31, 1985).

24. H.R. 3074 was introduced by Representative Jeffords on July 24, 1985.

ties could also assume FERC's current powers to regulate purely intrastate wholesale sales of electricity.

Supporters of these proposals argue that regional planning would lead to more cost-effective electric service by encouraging the acquisition of new generation capacity and the use of existing resources according to regional needs. Large interstate utilities would face a less conflicting set of regulatory forces. In addition, multistate compacts could help create regional markets where electric suppliers would vie for customers.

Opponents of regional compacts contend that this approach would only create an unnecessary new layer of regulation, because states already have adequate statutory authority to coordinate their regulatory efforts when such efforts are cost-effective. Regional electricity markets could best be fostered not by increased regulation, but by phased deregulation of the generation sector of the industry. Opponents also believe that regional compacts' requests for mandatory power transfers should not be allowed to bypass the limits on third party access specified by the Federal Power Act. Finally, opponents object to proposals to transfer federal wholesale ratemaking authority partially to the states, preferring such powers to remain with the FERC. In this view, discretionary transfer of rate authority to the states could impede utilities' current voluntary coordination efforts.

APPENDIXES

APPENDIX A

CASH-FLOW EFFECTS OF AFUDC AND CWIP RATE TREATMENT

The important financial differences of cost treatment under construction work in progress (CWIP) and allowance for funds used during construction (AFUDC) can probably best be understood by considering a hypothetical utility that has a $1.5 billion (in 1984 dollars) rate base in 1972.[1] The average cost of electricity is 5 cents per kilowatt hour (kwh) in 1972. The firm begins construction of a nuclear plant that takes 12 years to build and becomes operational in 1984 at a cost of $3 billion. For simplicity, it is assumed that construction expenditures are made in 12 equal payments during the construction period. The firm is assumed to receive an allowed 13 percent real rate of return on its rate base. The new plant becomes operational in 1984. Consumption of electricity grows at 2.5 percent annually over the construction period.

The cost of building and generating power can differ considerably between the two accounting methods described here (see Figure A-1). During construction, electricity prices are higher with CWIP in the rate base because construction and financing costs are immediately passed on to the consumer. Conversely, an AFUDC account defers reimbursement of all construction and financing costs until the plant becomes operational; this keeps prices lower during construction but causes a sharp "spike" when the new plant comes on line. Starting at 5 cents per kilowatt-hour in 1971, electricity prices under CWIP treatment rise to almost 11 cents per kwh in 1983 compared with 9 cents per kwh with AFUDC pricing. When the plant becomes operational, however, prices rise to 13 cents per kwh in the AFUDC case, but remain virtually unchanged for the CWIP case. Allowing CWIP in the rate base can, therefore, prevent the occurence of "rate shock."[2]

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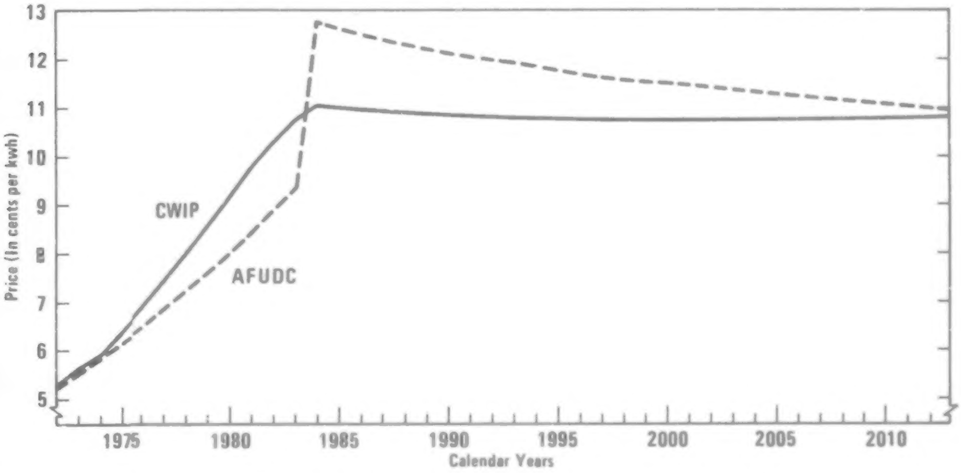
[1] The rate base is defined as the adjusted value of invested capital used and useful in rendering service to the public. The rate base includes generation, transmission, and distribution facilities providing service to consumers.

[2] Rate base phase-in plans are also used to reduce rate shock. See discussion in Chapter III.

Figure A-1.
CWIP and AFUDC Price Paths



SOURCE: Congressional Budget Office.

NOTE: In this hypothetical example, $1.5 billion in operation and maintenence (O & M) costs (including depreciation) for electricity production and distribution in 1981 are assumed to increase at 8 percent a year until 1984. After 1984, the utility's O & M expenses plus those for a new plant are assumed to grow at 3 percent per year for the next 30 years (the life of the plant). Dividing costs by consumption provides an average cost of electricity supply that is assumed to equal price.

The net present value of revenue needs under each accounting option also differs considerably.[3] Over the lifetime of the hypothetical plant, consumers would spend $500 million more for electricity with AFUDC pricing than with CWIP treatment, assuming a 9 percent discount rate. If the discount rate approaches the utility's cost of capital (assumed in this hypothetical case to be 13 percent), however, differences in consumers' expenditures become negligible. Consumers may, therefore, be indifferent about which pricing strategy is used, depending on investment conditions and the time value of money.

Arguments for CWIP pricing suggest that it may better approximate the true cost of providing new capacity than will AFUDC pricing and, as a result, provide appropriate investment incentives in the short run. As excess capacity dwindles and the new plant is being built, the marginal cost of providing power rises, since less efficient units typically are dispatched to meet demand. Electricity prices ought to reflect this when it occurs, if economic efficiency is to be achieved. From an investor's viewpoint, CWIP pricing is usually preferred to AFUDC pricing. An AFUDC discount does not add to a utility's cash flow, although it is treated as a component of a utility's total revenues. Thus, investors view increases in AFUDC as eroding the "quality" of a utility's earnings, making the utility a more risky investment. On the other hand, arguments against CWIP pricing suggest that it forces current consumers to subsidize future consumers.

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[3] Present value measures in today's dollars the cost of a future expenditure or stream of expenditures. Such calculations take into account the time value of money: that is, a dollar available today is worth more than a dollar available in the future.

APPENDIX B

DETERMINING WHICH INVESTOR-OWNED UTILITIES EXPERIENCED FINANCIAL STRESS

To identify those firms in financial difficulty, CBO examined financial data for 1983 and 1984 for 100 of the nation's largest investor-owned utilities. Using a fourfold screening process, 13 firms were identified as experiencing severe financial stress at that time (see Table 3 on p. 20). Five of the firms identified (Consumers Power, Long Island Lighting, Public Service of Indiana, Public Service of New Hampshire, and United Illuminating) were those with market-to-book ratios below .50. Middle South Utilities and Central Maine Power had market-to-book ratios of between 50 and 60 percent. Since September 1984, however, eight firms (Dayton Power & Light, Toledo Edison, Ohio Edison, Union Electric, Philadelphia Electric, Kansas Gas & Electric, Gulf States Utilities, and Kansas City Power & Light) have shown marked improvement by selling common stock at 80 percent or more of book value.

The screening process identifies financial stress--as indicated by intercompany comparisons of profitability, market performance, and liquidity--but it does not identify imminent bankruptcy.[1] This is because bankruptcy is not caused by a low market-to-book ratio or an inferior Standard & Poor's bond rating. Instead, bankruptcy occurs when financially weakened firms cannot absorb further cash-flow limitations, such as an unfavorable regulatory ruling or a drop in electricity demand. A firm could be included in more than one financial screen, yet still represent a low bankruptcy risk because external factors have stabilized.[2]

The CBO used four financial "screens" to avoid the shortcomings of using a single, arbitrary financial ratio (see Table B-1). The variables used

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[1] "Financial stress" is an imprecise concept, evading rigorous definition. It generally refers to the ease with which external capital may be raised by a firm for necessary investment and maintenance of cash flow. It refers to the firm's current financial condition and anticipations of this condition in the future. For this analysis, firms in financial stress are firms that emerge in at least three of the four CBO screening procedures.

[2] More sophisticated analytical methods, such as logit and discriminant analyses, could provide greater accuracy in predicting bankruptcy by using data from firms that actually have gone bankrupt. But, because utility bankruptcies have been rare, such a sample is not available.

TABLE B-1 FINANCIAL RATIO SCREENS USED TO IDENTIFY UTILITIES WITH LIQUIDITY CONSTRAINTS

Variable	Test Criteria	Description
SCREEN A Total Number of Firms--32		
Working Capital Divided by Total Assets	Less than 0	Measure of net liquid assets relative to total capitalization. Liquid assets = current assets minus current liabilities
Retained Earnings Divided by Total Assets	Less than 4%	Measure of cumulative profitability.
Earnings Before Interest and Taxes Divided by Total Assets	Less than 65%	Measure of productivity of a utility's assets less tax and leverage factors.
Market Value Divided by Book Value of Total Debt	Less than 75%	Measure of how much a utility's assets can decline in value before liabilities exceed assets and insolvency develops.
Sales Divided by Total Assets	Less than 1%	Measure of capital turnover.
SCREEN B Total Number of Firms--17		
Market Value Divided by Book Value of Common Stock	Less than 75%	Measure of how the financial community values the utility's future returns on common equity.
Rate of Return on Common Equity	Less than 11%	Measure of profitability of common equity.
Corporate Bond Rating	Less than BBB	Measure of long-term credit worthiness by Standard & Poor's.

(Continued)

TABLE B-1. (Continued)

Variable	Test Criteria	Description
SCREEN C Total Number of Firms--27		
Kidder, Peabody List of Utilities Facing Severe Capital Constraints (February 1984)	No specific financial measures	No financial ratios reported.
SCREEN D Total Number of Firms--18		
Market Value Divided by Book Value of Common Stock	Less than 75%	Measure of how the financial community values the utility's future returns on common equity.
Price Divided by Earnings of Common Stock	Less than $6	Measure of the stock market's value of a stock relative to a utility's profitability.
Estimated Total Construction Costs divided by Equity	Greater than 1	Measure of construction exposure.
Corporate Bond Ratings	Less than BBB	Measure of long-term credit worthiness by Standard & Poor's.

SOURCE: Congressional Budget Office.

in the four screens (A, B, C, D) were obtained from a variety of studies, and are generally well-accepted measures of market performance. Firm-specific quarterly data for 1983 and 1984 were used in the screenings. Only those firms appearing in at least three out of four screens were identified as financially weak (see Table B-2).

Screen A consists of five financial measures of liquidity, all found to be statistically significant indicators of financial weakness in other industries. 3/ These include measures of working capital, retained earnings, earnings before interest and taxes, and sales relative to total assets, as well as the standard market value to book value of total debt. The cut-off criteria for this screen are listed in the second column of Table B-1. Thirty-two firms out of the 100 examined emerged in this screen.

Screen B is composed of financial ratios that appeared in a recent econometric analysis of financial health in the electric utility industry. 4/ These three ratios are more illustrative of longer-term financial health than those found in screen A, but are often used by industrial analysts to select firms that may be particularly good investments. The criteria for poor performance include market-to-book stock ratio less than 75 percent, a rate of return on common equity less than 11 percent, and a corporate bond rating of BBB or less. Seventeen firms out of the 100 emerged in this screen.

Screen C, although without specific financial measures, is a list of utilities compiled by the investment banking firm of Kidder, Peabody & Co. 5/ It lists 27 utilities that "have been unable to raise sufficient capital from the bond or stock markets to complete their nuclear plant construction." Total construction cost estimates are compared with debt outstanding, equity, commercial paper, and sunk cost in nuclear plants as a percent of common equity. The Kidder, Peabody report also examined sociodemographic characteristics of shareholders and creditors. The CBO used the 27 listed firms as Screen C.

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3. Edward Altman, "Financial Ratios, Discriminant Analysis and the Prediction of Corporate Bankruptcy," *The Journal of Finance*, vol. XXIII, No. 4 (September 1968).

4. U.S. General Accounting Office, "Analysis of the Financial Health of the Electric Utility Industry" (June 11, 1984).

5. Eugene Meyer, "The Nuclear Utility Industry is Dead! So What? Should it be Revived?" Kidder, Peabody & Co., February 15, 1984.

TABLE B-2. UTILITIES IN FINANCIAL DISTRESS, 1984

Firm	Screen A	Screen B	Screen C	Screen D	Total
Central Maine	—	x	x	x	3
Consumers Power	x	x	x	x	4
Dayton Power & Light	x	x	x	x	4
Gulf States Utilities	x	x	x	x	4
Kansas City Power and Light	x	x	x	x	4
Kansas Gas & Electric	x	x	x	x	4
Long Island Lighting	x	x	x	x	4
Middle South Utilities	x	x	x	x	4
Ohio Edison	x	x	x	x	4
Philadelphia Electric	x	x	x	x	4
Public Service of Indiana	x	x	x	x	4
Public Service of New Hampshire	x	x	x	x	4
Toledo Edison	x	x	x	x	4
Union Electric	x	x	—	x	3
United Illuminating	x	x	x	x	4

SOURCE: Congressional Budget Office.

Screen D compares construction costs accumulated by utilities relative to their equity values. It also includes the price earnings ratio as an additional valuation measure. Eighteen firms appeared in this screen.

In this report, utilities were considered financially stressed if their quarterly ratios fell within the criteria of at least three of the four screens at any time in the four quarters of 1983 and the first three quarters of 1984. Table B-2 displays the results.

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Director

Erratum

Financial Condition of the
U.S. Electric Utility Industry
March 1986

On page 57, Chapter IV, the third sentence of the concluding paragraph should read:

> While current practices probably will not result in widespread electricity shortages, the nation's electricity supply could become less cost-effective if regulatory incentives continue to bias utilities away from capital investments regardless of their technical or economic merit.

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